NORTH CAROLINA UTILITIES COMMISSION

104th REPORT
JAN. 1, 2014
DEC. 31, 2014

ONE-HUNDRED FOURTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2014 THROUGH DECEMBER 31, 2014

ONE-HUNDRED FOURTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2014, through December 31, 2014

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

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

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

LETTER OF TRANSMITTAL

December 31, 2014

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, 2014, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2014, and ending December 31, 2014.

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

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

Edward S. Finley, Jr., Chairman

Bryan E. Beatty, Commissioner

Susan W. Rabon, Commissioner

ToNola D. Brown-Bland, Commissioner

Don M. Bailey, Commissioner

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TABLE OF CONTENTS

TABLE OF CONTENTS

2014 ANNUAL REPORT OF ORDERS AND DECISIONS OF THE NORTH CAROLINA UTILITIES COMMISSION

TABLE OF ORDERS AND DECISIONS PRINTED

NOTE: For Printed General Orders, see Index on Page 521

PAGE

DOCKET NO. E-100, SUB 111

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Consider Revisions to Commission Rule R8-60 on Integrated Resource Planning	)))	ORDER REQUESTING COMMENTS REGARDING RULE R8-60 AMENDMENTS

BY THE COMMISSION: General Statute 62-110.1(c) and G.S. 62-2(a)(3a) set forth certain policies and requirements for integrated resource planning (IRP) in North Carolina. The Commission implements G.S. 62-110.1(c) and G.S. 62-2(a)(3a) through the provisions of Commission Rule R8-60. By order issued on October 19, 2006, in Docket No. E-100, Subs 103, 110, and 111, the Commission opened a rulemaking proceeding "to consider revisions in the IRP process provided in Commission Rule R8-60."[1] On November 27, 2006, the Commission issued an order requesting comments and reply comments on proposed revisions to the Rule. Based upon the consensus reached among the parties and the reasonableness of the parties' proposed revisions, on July 11, 2007, the Commission issued its Order Revising Integrated Resource Planning Rules that adopted the current Rule R8-60 covering the reporting requirements for both the biennial IRP reports and the annual update reports. In summary, the revised rule establishes different IRP reporting requirements for even-numbered years and odd-numbered years. Beginning in 2008, and every two years thereafter, the electric utilities are required to file a biennial report that includes comprehensive IRP information. Beginning in 2009, and every two years thereafter, the electric utilities are required to file an annual report that updates the information contained in their last biennial reports. Pursuant to Rule R8-60(j), the procedure for intervention, comments, reply comments and hearing requests is the same for biennial and annual reports, except that initial comments are due within 150 days after the filing of biennial reports, but only 60 days after the filing of annual reports. Subsection (j) further requires that one or more public witness hearings shall be scheduled by the Commission.

In the Commission's 2013 IRP proceeding, in Docket No. E-100, Sub 137, several parties filed comments regarding the annual IRP reports and procedures.

In its April 11, 2014 comments, the Public Staff noted that despite the Commission's efforts to keep the IRP process within the established schedules, the annual IRP process has typically taken more than a year to complete. In addition, the Public Staff stated that the utilities have indicated that in order for Commission directives to be fully considered in their next IRPs they need to receive the inputs from the Commission in late spring or early summer prior to the next IRP filing deadline. Further, the Public Staff opined that the complexity of issues and sheer volume of information to be considered have resulted in a process that is sometimes disjointed and reactive, rather than constructive and deliberate. Therefore, the Public Staff believes that it may be appropriate to consider some changes to the IRP process to make it more robust and meaningful. Included among the changes considered by the Public Staff is a biennial process with less extensive

[1] The October 19, 2006 order was prompted by recommendations made by a workgroup that was created by the Commission in connection with the 2005 IRP proceedings in Docket No. E-100, Sub 103.

information required, but with more stakeholder involvement in the development of the inputs and scenarios to be used. For example, the Commission could require the utilities to include certain common scenarios and sensitivities that will be of interest to all participants and allow for better comparison of alternatives. In order to do so, the Commission may wish to consider issuing expedited rulings on key inputs and assumptions in order to ensure that these items are received in time to be fully incorporated by the utilities in their modeling processes. In addition, comments and public hearings on the annual update reports could be required only at the discretion of the Commission.

The Public Staff recommended that the Commission request comments from the electric utilities and other parties on potential changes to the IRP process that may assist in making the process more robust and effective for all of the parties involved.

According to Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc. (collectively, Duke) in their joint reply comments on May 23, 2014, the IRP process has expanded in scope over time through incremental annual IRP rulings, along with a growing number of special interest group intervenors participating in the IRP process. However, most of these intervenors focus only on issues of importance to their members or stakeholders. Further, they lack the obligation to provide reliable power delivery and the obligation for least cost planning on behalf of all Duke customers that the IRP planning process requires. In addition, Duke maintains that many of the individual issues now being raised by intervenors in the IRP dockets have their own focused regulatory proceedings. For example, the IRP clearly has overlap with EE, REPS, fuel, CPCN, avoided cost and rate case proceedings. However, the IRP was never intended to supplant or supersede these more focused proceedings. Duke further contends that several of the recommendations expressed by intervenors in their IRP comments are the same recommendations made within the context of the more focused proceedings. Thus, this moves the IRP process away from its main focus of long term planning toward more of a shorter term operational focus. Duke concludes by stating that it would be supportive of working toward productive revisions to the annual update process.

Dominion North Carolina Power (DNCP), in its May 23, 2014 reply comments, stated that it would welcome the opportunity to comment on the IRP process with an eye towards streamlining the annual updates to make them less burdensome. DNCP noted that its IRP process is ongoing and is designed to meet its biennial resource planning responsibilities in both Virginia and North Carolina. DNCP states that its IRP filing in Virginia is due on September 1 of each odd-numbered year. Thus, a streamlined update proceeding in North Carolina while DNCP is engaged in a full proceeding in Virginia would help DNCP maximize and conserve its planning resources.

Regarding stakeholder participation in the development of the utilities' IRPs, DNCP states that it does not believe a "North Carolina-wide" stakeholder process is necessary or would benefit each of the utilities in developing their IRPs. In addition, DNCP notes that its development of an IRP is a distinct process from Duke's planning process. However, DNCP does not oppose allowing up front input into its IRP process and has had a stakeholder review process in place in Virginia for several years. DNCP states that the Public Staff, Southern Environmental Law Center, Sierra Club and others routinely participate in its Virginia stakeholder review process and that this forum could be opened to other interested parties from North Carolina as well.

In its June 30, 2014 Order Approving Integrated Resource Plan Annual Update Reports and REPS Compliance Plans, the Commission noted these issues and included the following conclusion in its Order:

> The Commission understands the time and complexity concerns that the parties have with the current IRP planning process. Between the time extension requests and the increasing complexity of the issues raised during the proceedings, it makes for drawn out IRP timelines. The Commission agrees that some modifications might be warranted, especially to these odd-year annual update proceedings. For this reason, the Commission intends to open a future docket which will request comments and reply comments on the specific issues of what might be done to streamline the annual update reporting process so that it does not simply become another biennial proceeding with a different name.

Based on the foregoing and the record, the Commission is of the opinion that there is good cause to request comments from the Public Staff and all interested parties regarding possible revisions to the procedures that the Commission will employ in its review of the IRP annual reports filed in odd-numbered years. Further, the Commission finds good cause to specify that the Public Staff and other parties should address the following issues, in addition to any other points that they desire to comment upon.

(1) Whether the Public Staff should be the only party expressly allowed to file comments and recommendations about the annual reports?
(2) Whether the Commission should be required to make a finding of necessity before a public witness and/or evidentiary hearing is scheduled?
(3) Whether there are categories of information or particular subjects that are not necessary for inclusion in the annual reports?
(4) Whether there are procedures or methods that should be adopted to achieve more stakeholder involvement in the annual reports prior to the reports being filed with the Commission?

IT IS, THEREFORE, ORDERED as follows:

1. That this docket is hereby reopened. All filings related to this review of Commission Rule R8-60 shall be filed in this docket.

2. That all persons that previously intervened in this docket shall be entitled to participate in this docket without the necessity of filing a petition to intervene.

3. That on or before November 7, 2014, persons having an interest in this matter may file petitions to intervene.

4. That the Chief Clerk shall serve this Order Requesting Comments on all persons that previously intervened in this docket.

5. That on or before November 7, 2014, all parties may file initial comments.

6. That on or before December 5, 2014, all parties may file reply comments.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of September, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner James G. Patterson did not participate in this decision.

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	FINAL ORDER MODIFYING THE
Session Law 2007-397	)	POULTRY AND SWINE WASTE
	)	SET-ASIDE REQUIREMENTS AND
	)	PROVIDING OTHER RELIEF

HEARD: Tuesday, November 5, 2013, 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, Susan W. Rabon, ToNola D. Brown-Bland, Jerry C. Dockham, and James G. Patterson

APPEARANCES:

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

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, P.O. Box 1551, NCRH 20, Raleigh, North Carolina 27602

For Dominion North Carolina Power, Inc.:

E. Brett Breitschwerdt and Mary Lynne Grigg, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For GreenCo Solutions, Inc.:

Richard M. Feathers, GreenCo Solutions, Inc., 3400 Sumner Boulevard, P.O. Box 27306, Raleigh, North Carolina 27611-7306

For North Carolina Eastern Municipal Power Agency and North Carolina Municipal Power Agency No. 1:

Daniel C. Higgins, Burns, Day & Presnell, P.A., P.O. Box 10867, Raleigh, North Carolina 27605

For EnergyUnited Electric Membership Corporation:

Phillip Harris, Nelson Mullins Riley & Scarborough LLP, GlenLake One, Suite 200, 4140 Parklake Avenue, Raleigh, North Carolina 27612

For the Public Works Commission of the City of Fayetteville:

James P. West, West Law Offices, P.C., 434 Fayetteville Street, Suite 2325, Raleigh, North Carolina 27601

For the Tennessee Valley Authority:

Mark S. Calvert, Senior Attorney, Tennessee Valley Authority, 400 W. Summit Hill Drive, WT 6A, Knoxville, Tennessee 37902

For the North Carolina Sustainable Energy Association:

Michael D. Youth, North Carolina Sustainable Energy Association, 1111 Haynes St, Raleigh, North Carolina 27604

For Green Energy Solutions NV, Inc.:

R. Sarah Compton, PO Box 12728, Raleigh, North Carolina 27605

For the North Carolina Pork Council:

Kurt J. Olson, Law Office of Kurt J. Olson, 3737 Glenwood Avenue, Suite 100, Raleigh, North Carolina 27612

For North Carolina Poultry Federation, Inc:

Henry W. Jones, Jr., Jordan Price Wall Gray Jones & Carlton, 1951 Clark Avenue, Raleigh, North Carolina 27605

For the Using and Consuming Public:

Robert S. Gillam and Tim R. Dodge, Staff Attorneys, North Carolina Utilities Commission – Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On November 29, 2012, in the above-captioned proceeding, the Commission issued an Order (2012 Delay Order) modifying the 2012 poultry and swine waste set-aside requirements under the State's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) established in G.S. 62-133.8. These requirements are set forth in subsections (e) and (f) of G.S. 62-133.8, establishing set-asides within the electric power suppliers' overall renewable energy requirement. Pursuant to the 2012 Delay Order, the Commission eliminated the 2012 swine waste set-aside requirement for all electric power suppliers and delayed by one year the poultry waste set-aside requirement for all electric power suppliers. Consistent with that Order, the electric power suppliers, in the aggregate, were required to comply with the requirements of G.S. 62-133.8(e) according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2013-2014	0.07%
2015-2017	0.14%
2018 and thereafter	0.20%

Further, the electric power suppliers, in the aggregate, were required to comply with the requirements of G.S. 62-133.8(f) according to the following schedule:

Calendar Year	Requirement for Poultry Waste Resources
2013	170,000 megawatt hours
2014	700,000 megawatt hours
2015 and thereafter	900,000 megawatt hours

On September 16, 2013, Duke Energy Carolinas, LLC (DEC);[1] Duke Energy Progress, Inc. (DEP);[2] Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP);[3] GreenCo Solutions, Inc. (GreenCo);[4] the Public Works Commission of the City of Fayetteville (Fayetteville); EnergyUnited Electric Membership Corporation (EnergyUnited); Halifax Electric Membership Corporation (Halifax); and the Tennessee Valley Authority (TVA)[5] (collectively, the Joint Movants) filed a Joint Motion to Modify and Delay the 2013 Requirements of N.C.G.S. 62-133.8(e) and (f) Due to Lack of Sufficient Swine and Poultry Waste (Joint Motion).

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[1] DEC asserted that it is also acting in its capacity as REPS compliance aggregator for Blue Ridge Electric Membership Corporation (EMC), Rutherford EMC, the City of Dallas, Forest City, the City of Concord, the Town of Highlands and the City of Kings Mountain.

[2] DEP asserted that it is also acting in its capacity as REPS compliance aggregator for the towns of Sharpsburg, Lucama, Black Creek, and Stantonsburg, and the City of Waynesville.

[3] Dominion asserted that it is also acting in its capacity as REPS compliance aggregator for the Town of Windsor.

[4] In its September 3, 2013 REPS compliance plan in Docket No. E-100, Sub 113, GreenCo stated that its members are Albemarle 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. GreenCo has stated that it also provides REPS compliance services for Broad River Electric Cooperative and Mecklenburg Electric Cooperative, and that the REPS requirements for the Town of Oak City are included in the requirements for Edgecombe-Martin County EMC.

[5] TVA asserted that it is acting in its capacity as REPS compliance aggregator for Blue Ridge Mountain EMC, Mountain Electric Cooperative, Tri-State EMC and Murphy Electric Power Board.

On September 20, 2013, the North Carolina Eastern Municipal Power Agency (NCEMPA)[1] and North Carolina Municipal Power Agency Number 1 (NCMPA1)[2] (collectively, the Power Agencies) filed a similar joint motion requesting that the Commission delay the 2013 poultry and swine waste set-aside requirements for one year (Power Agency Motion).

Both the Joint Movants and the Power Agencies requested that the Commission, pursuant to G.S. 62-133.8(i)(2), often referred to as the "off-ramp" provision of the REPS statute, grant relief from compliance with the 2013 poultry and swine waste set-aside requirements by ordering a one-year delay of both set-aside requirements. G.S. 62-133.8(i)(2) states that the Commission may modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of G.S. 62-133.8 in whole, or in part, if the Commission determines that it is in the public interest to do so. General Statute 62-133.8(i)(2) requires that each electric power supplier requesting relief demonstrate that it made a reasonable effort to meet the requirements set out in the REPS statute.

On September 23, 2013, the Commission issued an Order Scheduling Hearing and Requiring Testimony setting the matter for hearing, establishing deadlines for filing testimony, and requiring the Joint Movants and Power Agencies to respond to questions posed by the Commission. The Order directed each electric power supplier, or its REPS compliance aggregator, to address: (1) the actions it has taken to meet the swine waste and poultry waste requirements; (2) the number of poultry and swine waste renewable energy certificates (RECs) it is currently required to retire for 2013 compliance; and (3) the number of poultry and swine waste RECs it anticipates that it will own by the end of 2013.

On October 11, 2013, DEC and DEP filed the direct testimony of Jonathan L. Byrd, Manager of Renewable Strategy and Compliance; DNCP filed the direct testimony of Chiman H. Muchhala, Manager of Market Operations; Halifax filed the direct testimony of Charles H. Guerry, Executive Vice President; EnergyUnited filed the direct testimony of Alec Natt, Chief Financial Officer; Fayetteville filed the direct testimony of Keith Lynch, Power Contracts and Regulatory Manager; NCEMPA and NCMPA1 filed the direct testimony of Andrew M. Fusco, Vice President of Member Planning and Corporate Services, ElectriCities of North Carolina, Inc.; GreenCo filed the direct testimony of Jason B. Nemeth, Director, Business Operations; and TVA filed the direct testimony of David B. DeHart, Program Manager, Renewable Energy.

On October 21, 2013, the Commission issued an Order Rescheduling Hearing, rescheduling the evidentiary hearing from November 6, 2013, to November 5, 2013.

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[1] According to its August 26, 2013 filing in Docket No. E-100, Sub 139, NCEMPA provides REPS compliance services for the following municipalities, which are also members of NCEMPA: Apex, Ayden, Belhaven, Benson, Clayton, Edenton, Elizabeth City, Farmville, Fremont, Greenville, Hamilton, Hertford, Hobgood, Hookerton, Kinston, LaGrange, Laurinburg, Louisburg, Lumberton, New Bern, Pikeville, Red Springs, Robersonville, Rocky Mount, Scotland Neck, Selma, Smithfield, Southport, Tarboro, Wake Forest, Washington, and Wilson. (The City of Wilson meets the REPS compliance requirements of the towns of Pinetops, Macclesfield, and Walstonburg.)

[2] According to its August 26, 2013 filing in Docket No. E-100, Sub 139, NCMPA1 provides REPS compliance services for the following municipalities, which are also members of NCMPA1: Albemarle, Bostic, Cherryville, Cornelius, Drexel, Gastonia, Granite Falls, High Point, Huntersville, Landis, Lexington, Lincolnton, Maiden, Monroe, Morganton, Newton, Pineville, Shelby, and Statesville.

On October 25, 2013, the Public Staff filed the testimony of Jay B. Lucas, Electric Engineer; the North Carolina Pork Council (Pork Council) filed the testimony of Angela W. Maier, Director of Policy Development and Communications; and the North Carolina Poultry Federation, Inc. (NCPF), filed the testimony of Summer Lanier, Public Relations Director, Prestage Farms, Inc.

On October 28, 2013, Green Energy Solutions NV, Inc., filed a written statement of position, but did not file testimony.

On November 1, 2013, the Power Agencies filed the rebuttal testimony of witness Fusco, and Fayetteville filed the rebuttal testimony of witness Lynch. Also on that date, Dominion filed a letter stating that it accepted Public Staff witness Lucas' recommendations to approve the relief requested in the Joint Motion subject to the conditions outlined in witness Lucas' testimony.

On November 5, 2013, the Commission issued an Order stipulating the testimony of Halifax witness Guerry and EnergyUnited witness Natt into evidence and excusing these witnesses from attending the hearing.

On November 5, 2013, the matter came on for hearing as scheduled. DEC and DEP presented the direct testimony of witness Byrd; TVA presented the direct testimony of witness DeHart; the Power Agencies presented the direct and rebuttal testimony of witness Fusco; Fayetteville presented the direct and rebuttal testimony of witness Lynch; the Pork Council presented the testimony of witness Maier; and the Public Staff presented the testimony of witness Lucas. The testimonies of GreenCo witness Nemeth, DNCP witness Muchhala, and NCPF witness Lanier were also stipulated into evidence and entered into the record at the opening of the hearing.

On November 12, 2013, DEC and DEP submitted a late-filed exhibit requested by Chairman Finley during the hearing.

On November 14, 2013, the Public Staff and NCMPA1 jointly submitted a late-filed exhibit requested by Chairman Finley during the hearing.

On November 26, 2013, NCPF and TVA each filed briefs. On November 27, 2013, the Power Agencies, the Public Staff, and the Joint Movants (excluding TVA) each filed proposed orders, the Pork Council filed a brief, and the North Carolina Sustainable Energy Association filed a letter supporting NCPF. Also on November 27, 2013, North Carolina Electric Membership Corporation filed a letter responding to the November 12, 2013 DEC/DEP late-filed exhibit.

On December 20, 2013, the Commission issued a Notice of Decision and Order stating that, due to the timing of the motions by the Joint Movants and the Power Agencies, it was not possible for the Commission to develop its complete order before the end of 2013, but that the Commission had made its decision in this docket. The Notice of Decision provided notice that the Commission would issue an order (1) delaying the 2013 requirements of G.S. 62-133.8(e) and (f), as established in the 2012 Delay Order, for one year; (2) requesting that the Public Staff arrange and facilitate two stakeholder meetings a year during 2014 and 2015; and (3) applying the triannual filing requirement first required by the 2012 Delay Order to DNCP, GreenCo, Fayetteville, EnergyUnited, Halifax, NCEMPA and NCMPA1.

The Notice of Decision and Order stated that a final Order, including findings of fact and conclusions, would be issued at a later date. The instant Order is that final Order, and the time for filing an appeal from the decision of the Commission shall begin to run on the date of issuance of this Order.

FINDINGS OF FACT

1. The State's electric power suppliers have made a reasonable effort to comply with the 2013 statewide swine and poultry waste set-aside requirements established by G.S. 62-133.8(e) and G.S. 62-133.8(f), but will not be able to comply.

2. Compliance with the set-aside requirements has been hindered by the fact that the technology of power production from poultry and swine waste continues to be in its early stages of development.

3. Compliance with the set-aside requirements has been hindered in some respects, and promoted in other respects, by the General Assembly, which has modified the REPS on several occasions and considered other proposals for additional modifications. Legislative and regulatory developments have made new options for compliance available to electric power suppliers; on the other hand, because of periodic proposals for change, many lenders and investors perceive the future of the REPS as uncertain.

4. Electric power suppliers and renewable power developers have worked in good faith to resolve issues previously determined to have hindered compliance, such as negotiation of power purchase agreement terms and conditions and the cost and time required to properly interconnect poultry and swine waste generation facilities with the electric grid. Despite these efforts, and a decrease in problems regarding interconnection and contractual language, developers of waste-to-energy facilities and their lenders and investors remain cautious and slow to act.

5. No party presented evidence that the aggregate 2013 poultry and swine waste set-aside requirements could be met; nor did any party oppose Joint Movants' and Power Agencies' motions for relief from the 2013 poultry and swine waste set-aside requirements.

6. It is in the public interest to delay required compliance by the State's electric power suppliers with the requirements of G.S. 62-133.8(e) and (f) for one year.

7. Although a few electric power suppliers indicated their ability to meet a pro-rata allocation of the statutory requirement, it is appropriate to delay the statutory deadlines of the poultry and swine waste set-aside requirements, not only for those electric power suppliers that have been unable to comply, but for all electric power suppliers.

8. Electric power suppliers that have acquired poultry and swine waste RECs for 2013 REPS compliance should be allowed to bank such RECs for poultry and swine waste set-aside requirement compliance in future years.

9. Electric power suppliers should continue to make efforts to purchase any reasonably-priced poultry and swine waste RECs available in order to support the construction and

operation of poultry and swine waste generation facilities and to fulfill requirements pursuant to this Order.

10. DEC and DEP should continue to file the verified triannual progress reports required by Ordering Paragraph No.4 of the 2012 Delay Order, and DNCP, GreenCo, Fayetteville, EnergyUnited, Halifax and the Power Agencies should also file these reports. The Power Agencies should be permitted to file their reports jointly if they so desire. The filing of these progress reports should continue until the Commission orders that they be discontinued.

11. It is appropriate for the Public Staff to arrange and facilitate two stakeholder meetings a year during 2014 and 2015.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 1-6

The evidence supporting these findings of fact appears in the testimony of DEC/DEP witness Byrd, DNCP witness Muchhala, TVA witness DeHart, Fayetteville witness Lynch, Power Agencies witness Fusco, EnergyUnited witness Natt, Halifax witness Guerry, GreenCo witness Nemeth, NCPF witness Lanier, Pork Council witness Maier, and Public Staff witness Lucas.

DEC/DEP witness Byrd testified that DEC and DEP worked diligently to comply with the 2013 poultry and swine waste set-aside requirements. Witness Byrd stated that DEP had acquired enough poultry RECs to meet its 2013 poultry waste set-aside requirement. Witness Byrd further testified, however, that DEC could not comply with its 2013 poultry waste set-aside requirement and that neither company was able to meet the 2013 swine waste set-aside requirement. Witness Byrd stated that DEC and DEP remain in active ongoing negotiations for the purchase of in-state poultry and swine RECs; they continue to explore opportunities to secure out-of-state RECs; they maintain open solicitations for additional poultry and swine resources; and they are making good-faith efforts to assist developers with difficulties in interconnecting facilities to the grid. In addition, witness Byrd stated that DEC is continuing to engage in swine waste research through its support of the Loyd Ray Farms project.

Witness Byrd stated that DEC and DEP have found that the production of electricity from poultry and swine waste is technologically challenging; it is more expensive than other more common forms of renewable energy; and that swine farms are typically located in very remote and rural areas, making interconnection costly and difficult. Further, witness Byrd stated that poultry and swine waste developers have encountered difficulties in financing their projects, in obtaining long-term supplies of animal waste fuel, and in other areas. As a result, developers have frequently delayed their commercial operation dates or abandoned their contracts with DEC and DEP. Witness Byrd stated that Commission decisions interpreting the poultry waste set-aside requirement, and the General Assembly's enactment of legislation affecting the requirement, caused DEC and DEP to frequently pause and reconsider their poultry waste compliance strategy, resulting in the loss of time. Witness Byrd testified that, in spite of all these difficulties, many of the poultry and swine waste developers who are working with DEC and DEP have made great strides. The developers have been confronted with a host of practical problems, and, as they have learned how to deal with these problems, they have brought their projects closer to commercial operation.

DNCP witness Muchhala testified that DNCP has participated in the Swine Waste REC Buyers Group organized by the electric power suppliers in North Carolina, has solicited numerous REC marketers and brokers, and has conducted its own search to locate operational swine waste digesters anywhere in the United States. According to witness Muchhala, all these efforts have failed and DNCP has not been able to acquire any swine waste RECs. Witness Muchhala testified that, because DNCP is permitted by statute to rely entirely on out-of-state sources, DNCP has been able to purchase sufficient out-of-state poultry RECs to meet the requirements of the poultry waste set-aside. However, DNCP has contracted to provide REPS compliance services for the Town of Windsor, which is required to provide 75 percent of its RECs from in-state sources, and it has not found any in-state swine or poultry waste RECs; consequently, DNCP is unable to comply with either of the 2013 poultry and swine waste set-aside requirements on Windsor's behalf.

TVA witness DeHart testified that TVA made reasonable efforts to comply with the 2013 poultry and swine waste set-aside requirements. Witness DeHart stated that TVA met with other North Carolina electric power suppliers to discuss joint efforts to purchase poultry and swine waste RECs, and, TVA has solicited offers from waste-to-energy developers for RECs or generation to meet the poultry and swine waste set-aside requirements. Witness DeHart testified that, despite these efforts, TVA is unable to comply with the 2013 poultry and swine waste set-aside requirements.

Fayetteville witness Lynch testified that Fayetteville is participating in the electric power suppliers' joint request for proposals (RFP) seeking poultry waste REC sales contracts; it has issued a separate RFP for swine waste RECs, to which no responses were received; and it has diligently assessed the market for opportunities to acquire poultry and swine waste RECs, but no such opportunities have been available. Witness Lynch's testimony as to whether Fayetteville will be able to meet the 2013 poultry and swine waste set-aside requirements was confidential.

Power Agencies witness Fusco testified that there is no reason to believe the State's electric power suppliers will be able to comply with the 2013 poultry and swine waste set-aside requirements. Witness Fusco stated that the Power Agencies, along with other electric power suppliers, entered into long-term swine REC purchase agreements with four counterparties; however, three of the counterparties repeatedly failed to meet the requirements of the agreements and the agreements were subsequently terminated. The contracts with the remaining counterparty are still in effect, but the project’s commercial operation date has been significantly delayed and the projected output has been reduced. Witness Fusco further stated that the Power Agencies have continued to look, with limited success, for other suppliers that could provide swine waste RECs. They were able to purchase swine waste RECs from an out-of-state supplier; however, this supplier's registration as a renewable energy facility was subsequently revoked by the Commission and the RECs were invalidated. With respect to poultry waste, witness Fusco stated that the Power Agencies have contracted to purchase RECs from various counterparties. However, according to witness Fusco, some of these counterparties' projects have failed and the others have been delayed.

Witness Fusco testified that in his view the reasons for the Power Agencies' difficulties in obtaining poultry and swine waste RECs include: (1) the small number of participants in the market for swine waste RECs; (2) the fact that most of the swine waste market participants lack actual experience with biomass technologies; (3) the lack of a website where animal waste generation projects can easily be identified and contacted; (4) the financing difficulties encountered by developers of poultry waste generation; (5) uncertainties arising from environmental regulatory permitting issues relating to poultry waste; and (6) the continuing legislative and regulatory developments directly affecting the poultry waste set-aside. Witness Fusco noted that, although these legislative and regulatory developments have created uncertainty, they have also expanded the universe of compliance options, and the Power Agencies are seeking to make use of these options. On cross-examination, witness Fusco testified that the Power Agencies have contracted with developers managing the proposed ReVenture project, which was expected to come on line by the end of 2013. According to witness Fusco, if the Reventure project remains on schedule and is on line in 2014, the Power Agencies will be able to meet the requested modified requirements of the poultry waste set-aside for 2014.

EnergyUnited witness Natt stated that EnergyUnited has purchased out-of-state poultry and swine waste RECs, and, that it has engaged in collaborative efforts with other North Carolina electric power suppliers to obtain in-state RECs. His testimony on whether EnergyUnited will be able to comply with the 2013 poultry and swine waste set-aside requirements was confidential.

Halifax witness Guerry did not appear at the hearing. Witness Guerry’s testimony was admitted into the record pursuant to the Commission's November 5, 2013 Order. He testified that Halifax participated in the collaborative efforts of the State's electric power suppliers to obtain poultry and swine waste RECs, but, to date those efforts have been unsuccessful. Witness Guerry stated that Halifax entered into an individual agreement to purchase RECs from a swine waste-to-energy developer, however, this developer has not yet registered with the Commission as a renewable energy facility. Consequently, according to witness Guerry, Halifax is unable to meet the 2013 poultry and swine waste set-aside requirements.

GreenCo witness Nemeth testified that GreenCo has participated in the collaborative efforts of the State's electric power suppliers to obtain poultry and swine waste RECs, and in addition, GreenCo has had discussions with numerous developers seeking to produce power from animal waste. As a result of these discussions, GreenCo has purchased some swine waste RECs both in-state and out-of-state, and some out-of-state poultry waste RECs. However, according to witness Nemeth, GreenCo has not acquired enough RECs to meet the 2013 poultry and swine waste set-aside requirements.

NCPF witness Lanier testified that NCPF does not oppose the request for a delay of one year to the poultry waste set-aside requirements. Witness Lanier stated that her employer, Prestage Farms, Inc., is in the process of developing a poultry litter gasification facility in Bladen County. Witness Lanier listed the benefits of generating power from poultry litter, emphasizing that power generation will provide a beneficial use for poultry waste in the event that the current practice of land application is prohibited.

Pork Council witness Maier testified that, although the development of electric generation from swine waste has taken time, significant gains are being made. Witness Maier stated that there are six permitted projects in North Carolina, including a 1.3-MW facility being developed by Revolution Energy in the town of Magnolia, which is expected to be fully operational in November 2013. She noted that the use of swine waste for power generation provides an alternative to the disposition of waste in lagoons, which has disadvantages and resulted in a moratorium on the expansion of the hog industry in the State. Witness Maier stated that with the enactment of the swine waste set-aside requirement, the State's electric power suppliers were given the responsibility to actively support and assist in the development of energy production from swine waste. In witness Maier's opinion, this responsibility has not been fully embraced by all electric suppliers. She asserted that the electric suppliers should make greater efforts to ensure that the language of their REC purchase contracts does not place unreasonable burdens on developers. Finally, witness Maier recommended that the provision contained in the 2012 Delay Order, requiring DEC and DEP to file triannual progress reports, be made applicable to all of the State's electric power suppliers.

Public Staff witness Lucas testified that the Joint Movants' and the Power Agencies' motions should be granted because the electric power suppliers are unable to comply with the 2013 poultry and swine waste set-aside requirements. Witness Lucas stated that, even though DEC and DEP have not acquired enough poultry and swine waste RECs to meet the requirements, it is clear that they have made good-faith efforts to do so. Witness Lucas further stated his belief that the other electric power suppliers have made good-faith efforts to comply, but that he cannot say so with the same degree of certainty because the other suppliers have not been required to meet the same level of transparency and additional reporting requirements that DEC and DEP were required to adhere to pursuant to the 2012 Delay Order.

Witness Lucas further testified that at the hearing prior to the 2012 Delay Order, he identified several factors that made compliance with the set-asides difficult, including: (1) uncertainty as to the environmental requirements applicable to waste-to-energy facilities; (2) uncertainty arising from the numerous statutory amendments affecting the poultry waste set-aside; (3) disagreements between electric power suppliers and developers on contract terms, particularly those relating to change of law provisions; and (4) difficulties in reaching satisfactory interconnection agreements. Witness Lucas stated that uncertainty surrounding potential changes to the REPS statute continues to exist, while the uncertainty about environmental requirements has diminished to some degree because several waste-to-energy facilities have received rulings from the Division of Air Quality of the North Carolina Department of Environment and Natural Resources that they are not subject to the restrictions applicable to solid waste incinerators. Witness Lucas further stated that most of the contractual issues relating to change of law have largely been addressed and the difficulties with interconnection agreements have for the most part been resolved.

In its determination that the effective dates of the poultry and swine waste set-asides should again be delayed, the Commission initially notes that its authority under G.S. 62-133.8(i)(2) "to modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of [G.S. 62-133.8) in whole or in part" may be exercised only if the electric power suppliers requesting the modification or delay "demonstrate that [they] made a reasonable effort to meet the requirements set out" in the statute. In this case, the evidence demonstrates that the electric power suppliers made reasonable efforts to comply with their 2013 poultry and swine waste set-aside requirements. However, no supplier is able to comply with the 2013 swine waste set-aside requirement and a limited few are in a position to comply with the 2013 poultry waste set-aside requirement. Witnesses Maier and Lucas expressed some concern as to whether certain suppliers' compliance efforts might have been more vigorous and extensive, but neither contended that any supplier failed to make a reasonable effort. The Commission concludes that the limited availability of poultry waste RECs, and the near unavailability of swine waste RECs, resulted in a scenario in which compliance could not be achieved. The primary cause of these limitations is the immature and undeveloped state of the technology of electric power generation from poultry and swine waste. Many states have adopted renewable energy portfolio standards, however, North Carolina is the only state with set-aside requirements for energy generated from swine or poultry waste. Witnesses Byrd, Fusco and Nemeth testified that almost every developer that agreed to provide power from poultry or swine waste had to postpone startup dates or abandon the projects entirely.

The evidence shows little disagreement regarding other causes of the electric power suppliers' difficulty with compliance in 2013. Witnesses Byrd, Fusco and Lucas all noted that new legislative developments affecting the poultry waste set-aside have resulted in uncertainty and delays, although they have also provided suppliers with new ways of complying with the set-aside. Witness Lucas further testified that there have been disputes about the terms and conditions of REC purchase agreements and disagreements and misunderstandings as to the interconnection of facilities. The testimony of these witnesses was not contradicted by any party.

The Commission notes that despite setbacks, which are inevitable with the development of a new technology, several of the State's waste-to-energy developers are making significant strides. Witness Byrd testified that many developers have made significant progress and are close to having their facilities on line. Additionally, witness Byrd stated that DEP is in a position to comply with its 2013 poultry waste set-aside requirement. Witness Fusco stated that the ReVenture project was expected to begin producing poultry waste RECs by the end of 2013; witness Nemeth indicated that GreenCo is purchasing a small amount of in-state swine waste RECs; and witness Lanier testified that the Revolution Energy swine waste plant in Magnolia is scheduled to come on line in the near future.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 7-9

The evidence supporting these findings of fact appear in the testimony of DNCP witness Muchhala and Power Agencies witness Fusco.

DNCP witness Muchhala testified that, despite the fact that DNCP is in compliance with the 2013 poultry waste set-aside requirements and the Town of Windsor has acquired some poultry waste RECs, their compliance schedule should be delayed uniformly with the other electric power suppliers. Witness Muchhala further testified that DNCP should be allowed to bank its already acquired RECs for future use. Witness Muchhala contended that this approach maintains fairness among the electric power suppliers and is appropriate because the poultry waste set-aside requirement is a joint annual compliance requirement to be achieved by all the electric power suppliers.

Power Agencies witness Fusco testified that, if any electric power supplier is granted a delay to the 2013 poultry and swine waste set-aside requirements, the same relief should be granted to those electric power suppliers capable of whole or partial compliance. Witness Fusco stated that if suppliers that incurred costs in good faith to acquire poultry and swine waste RECs are required to retire those RECs in 2013, while those suppliers who acquired no RECs are excused from compliance, the practical effect is that the suppliers who purchased RECs will be penalized for good faith efforts to comply with the requirements.

No party offered testimony in opposition to the contentions of witnesses Muchhala and Fusco.

In the 2012 Delay Order the Commission modified the 2012 poultry and swine waste set-aside requirements uniformly for all parties, including those that were able to fully or partially comply with the set-asides, as well as those that had not acquired any swine or poultry waste RECs. Further, the Commission allowed parties that had acquired RECs to bank them for compliance in future years. The Commission directed all electric power suppliers to continue to make efforts to purchase any reasonably priced poultry and swine waste RECs that were available. These procedures are fair to all parties and are not opposed by any party to this proceeding. Further, the nature of the poultry and swine waste set-aside requirements, as aggregate requirements, would render compliance planning exceedingly complex were different electric power suppliers held to different compliance schedules. Consequently, the Commission will adopt the same procedures for use in this proceeding. However, the Commission notes that, as poultry and swine waste RECs become more readily available and more electric power suppliers are able to comply with the requirements, the Commission reserves the right to revisit the uniform application of compliance delays in potential future proceedings if the Commission finds it necessary to do so.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 10-11

The evidence supporting these findings of fact appear in the testimony of Public Staff witness Lucas, Pork Council witness Maier, Fayetteville witness Lynch, and Power Agencies witness Fusco.

Public Staff witness Lucas testified that the triannual progress reports, currently filed by DEC and DEP pursuant to Ordering Paragraph No. 4 of the Commission's 2012 Delay Order, should also be filed by DNCP, TVA, Fayetteville, the Power Agencies, and GreenCo. He stated that this requirement would provide greater transparency as to these suppliers' compliance efforts. On cross-examination and redirect, witness Lucas testified that the triannual progress reports should not only include the names of developers with whom a supplier has had discussions and the reasons why these discussions did or did not lead to a REC purchase contract, but should also include some degree of detail as to each developer's proposal. In witness Lucas’ opinion, the preparation of an electric power supplier's initial progress report will require some effort. However, subsequent reports should be relatively easy to prepare since the electric power supplier can use its first report as a template and insert new information or delete outdated material as needed.

Pork Council witness Maier testified that the triannual reports should be filed by all electric power suppliers. Witness Maier stated that these reports include useful information about the suppliers' compliance efforts, provide additional incentive for the suppliers to focus on compliance with the poultry and swine waste set-asides, and give interested parties an opportunity to intercede if necessary. Further, witness Maier suggested that periodic stakeholder meetings would help reduce uncertainty by displaying a commitment on the part of developers and the electric power suppliers.

Power Agencies witness Fusco stated that he did not believe the electric power suppliers, other than DEC and DEP, should be required to file triannual reports. Witness Fusco stated that DEC and DEP agreed to file these reports in a settlement agreement in the 2012 proceeding. However, the other electric power suppliers were not parties to the settlement agreement and never agreed to file the reports. Witness Fusco stated that electric power suppliers already file annual compliance plans and compliance reports, and additional reporting requirements would be overly burdensome and would not produce any additional RECs. Witness Fusco stated that, in his opinion, the only obligation of the electric power suppliers under G.S. 62-133.8 is to acquire the number of RECs specified in the statute; they are not required to actively support and assist in the development of renewable energy.

On cross-examination, witness Fusco stated that the labor costs required to compile a triannual report and have it reviewed by the Power Agencies' legal staff would be significant, amounting to about $1,000. He agreed that the triannual reports would help keep the Commission abreast of the electric power suppliers' compliance efforts and would provide the electric power suppliers with an opportunity to bring their concerns forward to the Commission. Witness Fusco stated that the Power Agencies' annual compliance reports and compliance plans are filed in September and their off-ramp motion this year was also filed in September. Witness Fusco acknowledged that for the rest of the year, if they are not required to file triannual reports, the Power Agencies will not make any information available about their compliance activities.

Fayetteville witness Lynch testified that Fayetteville should not be burdened with preparing triannual reports because it is a small supplier and its efforts to comply with the poultry and swine waste set-aside requirements are limited to participating in purchasing collaboratives. On cross-examination, witness Lynch agreed that swine and poultry production are important industries to the State's economy that produce an undesirable waste product, and that in enacting G.S. 62-133.8(e) and (f) the General Assembly hoped to create a way of disposing of this waste product while producing useful electric power. He further acknowledged that to achieve this goal the electric power suppliers and the waste-to-energy developers must cooperate in good faith, and, in particular, they must communicate with each other.

Whether to require triannual reports from electric power suppliers other than DEC and DEP is the only contested issue before the Commission in this proceeding. In this matter the Commission agrees with the Public Staff and the Pork Council. The triannual reports filed this year by DEC and DEP have been valuable to the Commission. The filing of similar reports by DNCP, GreenCo, Fayetteville, EnergyUnited, Halifax and the Power Agencies should likewise provide helpful information on their compliance activities; should help keep the Commission informed on whether progress is continuing toward making the generation of power from poultry and swine waste a practical reality; and should assist the Commission in ruling on similar future motions, if necessary. Further, the filing of triannual reports will provide regular notice to the Commission of electric power suppliers’ compliance, or lack thereof, with the poultry and swine waste set-aside requirements, rather than the Commission relying upon the electric power suppliers to file motions for relief, which have occurred late in the calendar year.

As witnesses Fusco and Lynch pointed out, the electric power suppliers will incur some costs in preparing triannual reports; however, the Commission agrees with witness Lucas that a supplier's second and subsequent reports will be less time-consuming and expensive than its first one. The Commission does not find this to be an unreasonable expense for larger electric power suppliers. The Commission has taken the cost of the reports into account, however, in choosing to exempt the smallest suppliers from the reporting obligation.

Accordingly, the Commission concludes that DNCP, GreenCo, Fayetteville, EnergyUnited, Halifax and the Power Agencies, as well as DEC and DEP, should be required to file the verified triannual Progress Reports required by Ordering Paragraph No. 4 of the Commission's 2012 Delay Order. Further, the Public Staff is requested to arrange and facilitate two stakeholder meetings a year during 2014 and 2015 that shall be attended by the electric power suppliers that are subject to the triannual reporting requirement. The purpose of the stakeholder meetings is to encourage communication between electric power suppliers and developers and to discuss potential obstacles to achieving compliance with the poultry and swine waste set-aside requirements and options for addressing them.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2013 requirement of G.S. 62-133.8(e), as established in the Commission’s 2012 Delay Order, is delayed for one year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62-133.8(e) according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2014-2015	0.07%
2016-2018	0.14%
2019 and thereafter	0.20%

2. That the 2013 requirement of G.S. 62-133.8(f), as established in the Commission’s 2012 Delay Order, is delayed for one year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62-133.8(f) according to the following schedule:

Calendar Year	Requirement for Poultry Waste Resources
2014	170,000 megawatt-hours
2015	700,000 megawatt-hours
2016 and thereafter	900,000 megawatt-hours

3. That the Public Staff is requested to arrange and facilitate two stakeholder meetings a year during 2014 and 2015. The electric power suppliers that are subject to the triannual filing requirement (as discussed herein) shall attend. Developers and other stakeholders are encouraged to participate and discuss potential obstacles to achieving the swine and poultry waste requirements and options for addressing them.

4. That the triannual filing requirement first required by the Commission’s 2012 Delay Order and that now applies to DEP and DEC shall apply to DNCP, GreenCo, Fayetteville, EnergyUnited, Halifax, NCEMPA and NCMPA1. The reports to be filed shall be due to the Commission on each May 1, September 1, and January 1, until the Commission finds that they are

no longer necessary. The filing requirements shall be as specified in ordering paragraph 4 of the Commission's 2012 Delay Order.

ISSUED BY ORDER OF THE COMMISSION
This the __26th___ day of March, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement	)	ORDER MODIFYING THE SWINE
Session Law 2007-397	)	WASTE SET-ASIDE REQUIREMENT
	)	AND PROVIDING OTHER RELIEF

BY THE COMMISSION: On August 28, 2014, a joint motion to modify and delay the 2014 requirements of G.S. 62-133.8(e) was filed by Duke Energy Carolinas, LLC (DEC);[1] Duke Energy Progress, Inc. (DEP);[2] Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion);[3] GreenCo Solutions, Inc. (GreenCo); Public Works Commission of the City of Fayetteville (Fayetteville); EnergyUnited Electric Membership Corporation (EnergyUnited); Halifax Electric Membership Corporation (Halifax); the Tennessee Valley Authority (TVA);[4] North Carolina Eastern Municipal Power Agency (NCEMPA);[5] and North Carolina Municipal Power Agency Number 1 (NCMPA1)[6] (hereinafter referred to collectively as the Joint Movants). The Joint Movants requested that the Commission relieve them of compliance with G.S. 62.133.8(e) (Compliance With [North Carolina's Renewable Energy and Energy

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[1] DEC asserted that it is also acting in its capacity as REPS compliance aggregator for Blue Ridge Electric Membership Corporation (EMC), Rutherford EMC, the City of Dallas, Forest City, City of Concord, the Town of Highlands and the City of Kings Mountain.

[2] DEP asserted that it is also acting in its capacity as REPS compliance aggregator for the Towns of Sharpsburg, Lucama, Black Creek, and Stantonsburg, and the City of Waynesville.

[3] Dominion asserted that it is also acting in its capacity as REPS compliance aggregator for the Town of Windsor.

[4] TVA asserted that it is acting in its capacity as REPS compliance aggregator for Blue Ridge Mountain EMC, Mountain Electric Cooperative, Tri-State EMC and Murphy Electric Power Board.

[5] NCEMPA asserted that it is acting in its capacity as REPS compliance aggregator for its 32 member municipalities which are electric power suppliers.

[6] NCMPA1 asserted that it is acting in its capacity as REPS compliance aggregator for its 19 member municipalities which are electric power suppliers.

Efficiency Portfolio Standard (REPS)] Requirement Through Use of Swine Waste Resources) by delaying their need to comply with this requirement by one year until 2015. The joint motion further requested that the Commission allow the Joint Movants to bank any swine renewable energy certificates (RECs) previously or subsequently acquired for use in future compliance years, and allow the Joint Movants to replace compliance with the swine waste requirements in 2014 with other compliance measures pursuant to G.S. 62-133.8(b), (c), and (d). The Joint Movants requested that the Commission consider and approve their joint motion without an evidentiary hearing.

The Joint Movants stated that they have individually and collectively made reasonable efforts to comply with the REPS swine waste resource provisions, and that the relief sought is in the public interest. The Joint Movants identified a number of actions taken to display their efforts to comply. Specifically, these actions, according to the Joint Movants, included actively engaging swine waste-to-energy developers, issuing requests for proposals, evaluating bids received, negotiating and executing long-term REC purchase agreements for these resources, processing interconnection requests from these generators, actively monitoring executed agreements, and, in some cases, further modifying REC purchase agreements to provide developers reasonable opportunity for successful project execution.

On September 17, 2014, the Commission issued an Order Requesting Comments in the above captioned docket, requesting that interested parties file comments on the Joint Movants' request on or before Friday, October 10, 2014. On October 9, 2014, Environmental Defense Fund (EDF) submitted comments. On October 10, 2014, the North Carolina Pork Council (NCPC) and the Public Staff submitted comments. No party submitted comments in opposition to the Joint Movants' request to delay the swine waste set-aside requirement.

EDF, in its comments, did not challenge the Joint Movant's request to delay the swine waste set-aside. EDF noted the increasing number of technologies by which swine waste may be converted to electricity, in particular, biogas. EDF stated that it does not support routine annual extensions and that they should not become the norm. EDF stated that the utilities should become more involved in the development of swine waste resources in future years to display that they have made a reasonable effort to comply with the swine waste set-aside requirement. EDF requested that the Commission (1) set forth enumerated milestones at which the utilities must publicly report to ensure that they remain on course for compliance and (2) require DEC and DEP to develop a stakeholder process to "scale" the requirement and establish subsequent deadlines. Finally, EDF attached to its comments an analysis completed by Duke University of options for collecting and using biogas generated from swine waste.

NCPC, in its comments, noted that this is the third straight year that the electric suppliers have asked to modify or delay compliance with the swine waste set-aside requirement. NCPC stated that it did not oppose the Joint Movants' request, however, NCPC noted that not much progress towards compliance has been made and added recommendations which it felt could help move the electric suppliers closer to achieving compliance. Specifically, NCPC requested (1) that the tri-annual reporting requirements be continued; and (2) that the Public Staff evaluate the prices offered to assess the reasonableness of efforts to comply and conduct an analysis of the relevant market, including price. NCPC also noted the Duke University study attached to EDF's comments as evidence that swine waste development, contrary to the claims of several electric power suppliers, can be done economically in North Carolina.

The Public Staff, in its comments, stated that it had reviewed the tri-annual reports as well as information obtained at stakeholder meetings. As a result of this review, the Public Staff stated its belief that the electric power suppliers, in general, are making a good faith effort to comply with the swine waste set-aside requirement. The Public Staff identified several problem areas affecting compliance including: interconnection; reluctance of farmers to sign long-term fuel supply agreements; the sunset of the federal production tax credit; uncertainty in contract fulfillment based on past lack of performance; air quality permit delays; issues in the anaerobic digestion process, including waste disposal; and the uncertainty caused by the previous delays to the swine waste set-aside requirement. The Public Staff noted potential solutions to these problems discussed at stakeholder meetings including: electric power suppliers and the public bearing more risk in swine waste facility construction and operation, and the allowance of back-up fuels to generate electricity for a period of time in which swine waste fuels may become unavailable. The Public Staff recommended that the Commission grant the Joint Movants' request to delay the swine waste set-aside requirement until 2015. The Public Staff further recommended that the Commission allow electric power suppliers to bank any swine waste RECs previously or subsequently acquired for use in future compliance years. Finally, the Public Staff recommended that the Commission proceed in this matter without a hearing.

G.S. 62-133.8(i)(2) states that the Commission, in developing rules, shall:

> Include a procedure to modify or delay the provisions of subsections (b), (c), (d), (e), and (f) of this section in whole or in part if the Commission determines that it is in the public interest to do so. The procedure adopted pursuant to this subdivision shall include a requirement that the electric power supplier demonstrate that it made a reasonable effort to meet the requirements set out in this section.

Commission Rule R8-67(c)(5) states:

> In any year, an electric power supplier or other interested party may petition the Commission to modify or delay the provisions of G.S. 62-133.8(b), (c), (d), (e) and (f), in whole or in part. The Commission may grant such petition upon a finding that it is in the public interest to do so. If an electric power supplier is the petitioner, it shall demonstrate that it has made a reasonable effort to meet the requirements of such provisions.

The Commission has previously exercised this authority and delayed compliance with the swine waste set-aside requirement on two occasions, first as delineated in its November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief (2012 Delay Order), and a second time as delineated in its March 26, 2014 Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief (2013 Delay Order), both issued in Docket No. E-100, Sub 113.

Based on the tri-annual reports submitted by the electric power suppliers in Docket No. E-100, Sub 113A, the Joint Movants' motion, the intervenors' comments, and the entire record herein, the Commission finds that the State's electric power suppliers have made a reasonable effort to comply with the 2014 statewide swine waste set-aside requirement established by G.S. 62-133.8(e), but will not be able to comply. Compliance with the set-aside requirements has been hindered by the fact that the technology of power production from swine waste continues to be in its early stages of development. Additional factors contributing to the inability to comply include interconnection issues, reluctance of farmers to sign long-term fuel supply agreements, uncertainty in contract fulfillment based on past lack of performance, and the uncertainty caused by the previous delays to the swine waste set-aside requirement, among others. No party presented evidence that the aggregate 2014 swine waste set-aside requirement could be met; nor did any party oppose the Joint Movants' request. The Commission further finds that it is in the public interest to delay required compliance by the State's electric power suppliers with the requirements of G.S. 62-133.8(e) for one year. Electric power suppliers that have acquired swine waste RECs for 2014 REPS compliance should be allowed to bank such RECs for swine waste set-aside requirement compliance in future years. Electric power suppliers should continue to make efforts to comply with the swine waste set-aside requirement as modified by this Order. In addition, all electric power suppliers subject to the tri-annual reporting requirements shall continue to file reports until the Commission orders that they be discontinued. Finally, it remains appropriate for the Public Staff to arrange and facilitate two stakeholder meetings during 2015.

The Commission does not find that good cause exists at the present time to grant EDF's request that the Commission set forth enumerated milestones at which the utilities must publicly report and that the Commission require DEC and DEP to develop a stakeholder process to "scale" the swine waste set-aside requirement. The Commission, in the 2012 Delay Order, as modified by the 2013 Delay Order, has established a tri-annual reporting requirement to track compliance efforts relative to both the swine and poultry waste set-aside requirements throughout the year. The purpose of the reports is to provide the Commission with an accurate portrayal of compliance efforts throughout the year and the reports have proven useful in this capacity. The Commission finds that the tri-annual reporting requirement has proven to be an adequate method to track compliance efforts over a given year, and, thus, EDF's request would result in unnecessary duplicative requirements.

IT IS, THEREFORE, ORDERED as follows:

1. That the 2014 requirement of G.S. 62-133.8(e), as established in the Commission's 2013 Delay Order, is delayed for one year. The electric power suppliers, in the aggregate, shall comply with the requirements of G.S. 62-133.8(e) according to the following schedule:

Calendar Year	Requirement for Swine Waste Resources
2015-2016	0.07%
2017-2019	0.14%
2020 and thereafter	0.20%

Electric power suppliers shall be allowed to bank any swine waste RECs previously or subsequently acquired for use in future compliance years and to replace compliance with the swine waste requirements in 2014 with other compliance measures pursuant to G.S. 62-133.8(b), (c), and (d).

2. That the Public Staff is requested to arrange and facilitate two stakeholder meetings during 2015. The electric power suppliers that are subject to the triannual filing requirement (as discussed below) shall attend. Developers and other stakeholders are encouraged to participate and discuss potential obstacles to achieving the swine and poultry waste requirements and options for addressing them.

3. That the tri-annual filing requirement first required by the Commission's 2012 Delay Order and that now, pursuant to the 2013 Delay Order, applies to DEP, DEC, Dominion, GreenCo, Fayetteville, EnergyUnited, Halifax, NCEMPA and NCMPA1 shall be due to the Commission on each May 1, September 1, and January 1, until the Commission finds that they are no longer necessary. The filing requirements shall be as specified in ordering paragraph 4 of the Commission's 2012 Delay Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of November, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-100, SUB 134

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Filing Requirements for New Electric Generators	)	ORDER AMENDING RULES AND
	)	REQUESTING COMMENTS ON
	)	ADDITIONAL PROPOSED RULE
	)	CHANGES

BY THE COMMISSION: On September 8, 2014, the Commission issued an Order Requesting Comments on Proposed Rule Changes in which it requested comments on proposed amendments to Commission Rules R8-61, R8-63, and R8-64. The proposed rule changes were intended to "facilitate more efficient review by government agencies and the general public of the potential environmental, cost, and fuel security impacts of proposed new electric generation facilities."

Subsequently, the Commission received comments from Carolinas Public Gas Association, Greenville Utilities Commission, City of Rocky Mount, City of Wilson, City of Monroe and City of Shelby (Public Gas Systems); Dominion North Carolina Power (Dominion); North Carolina Sustainable Energy Association (NCSEA); and the Public Staff. Duke Energy Carolinas, LLC and Duke Energy Progress, Inc., jointly filed a letter stating that they had reviewed the proposed changes and had no comments.

SUMMARY OF COMMENTS

Public Gas Systems

The Public Gas Systems assert that new gas-fueled power plants should be required to demonstrate that they have secured long-term firm gas supply and pipeline capacity prior to beginning construction. They note that North Carolina has experienced an increased demand for gas as a fuel for electric generation, and that "as this trend continues and new natural gas-fueled power plants are proposed, their impact on the natural gas market should be taken into account." They state:

> During normal operating and weather conditions, there is currently sufficient natural gas supply and pipeline capacity for electric generation facilities to operate without adverse impact to existing natural gas consuming customers. However, as reliance on natural gas for electric generation grows, the current market framework and infrastructure cannot ensure reliability, especially during extreme weather conditions.

The Public Gas Systems state further that they have seen many manufacturing customers that used natural gas year round close their operations.

> This shift in the economy has changed their [the Public Gas Systems] load profile to be more sensitive to temperature changes, as a greater percentage of their customers now use natural gas for space and water heating rather than for manufacturing. In addition … [t]hey have less pipe in which line pack can be stored or used to accommodate demand fluctuations. They serve less geographic territory over which temperatures may differ to allow system gas to be re-distributed. And they have few interruptible customers that can be curtailed to manage demand swings. All of these factors have made gas supply management increasingly difficult for the Public Gas Systems.
>
> Upon information and belief, many electric generation facilities do not purchase year-round firm pipeline capacity or enter into non-interruptible contracts so as to avoid the required demand charges and instead arrange by contract for delivery of natural gas "just-in-time" as needed – often at peak-energy-usage periods. This new entrant in the wholesale gas market has changed the supply and demand dynamics, with adverse impacts on the traditional market participants such as the Public Gas Systems.
>
> An example of an adverse impact to the market occurred during the January and February 2014 "polar vortex" periods. During those times, temperatures plunged far below normal for several days, and the Public Gas Systems needed to buy additional natural gas and capacity on the spot market to meet their customers' demand. During January 2014, Transco Zone 5 (North Carolina) gas prices averaged over $24 per dekatherm (Dt) per day, with seven days exceeding $40 per Dt, and a one-day spike of $118. This compares with the previous January in 2012

> [sic] when the average daily price for the month was $4.42 per Dt. At least one Public Gas System had to purchase natural gas on the spot market in Zone 6 NNY at $123 per dekatherm.
>
> . . .
>
> This rulemaking docket for new electric generation facilities provide[s] the Commission with an opportunity to send a clear signal that future electric generation facilities will need to secure firm pipeline capacity and to participate in efforts to improve pipeline infrastructure and enhance long-term reliability.

The Public Gas Systems express support for rule changes proposed by the Commission that would require electric power supplier applicants for natural gas-fired facilities with a capacity of 300 megawatts (MW) or more to provide “a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated gas facilities to be constructed to serve the facility and any filed agreements, service contracts, or tariffs for interstate pipeline capacity.” (Currently, this provision only applies to merchant facilities, not public utilities.) The Public Gas Systems also supported the proposed change that would require applications for certificates of public convenience and necessity (CPCN) qualifying co-generators and small power producers to include “the nature of the generating facility, including the type and source of its power or fuel.” The Public Gas Systems stated that this additional information will help reveal the extent that new generation facilities will impact the wholesale natural gas market as a whole and the collateral effects they may have on other market participants.

Similarly, the Public Gas Systems state that they support the proposed new requirement for new gas-fired generators owned by public utilities to file “a statement of how the facility would contribute to resource and fuel diversity, whether the facility would have dual-fuel capability, and how much fuel would be stored at the site.” They also supported the proposed requirement that applicants demonstrate arrangements made or planned to assure a dependable fuel supply.

Dominion

Dominion expresses concern that applicants would be required to provide detailed financial information 120 days prior to a CPCN filing. This is an existing requirement for facilities that are 300 MW or larger. The Commission’s proposed rule change would: (1) require all CPCN applications that are filed by public utilities to include the financial information, not just those for plants of 300 MW or more; and (2) allow the utility to file the information with the CPCN, rather than 120 days in advance (as is currently required pursuant to Rule R8-61 for plants 300 MW and larger).

Regarding Rule R8-63, which governs filing requirements for merchant plants, Dominion states that the current requirement in Section (e)(3) should be changed. This provision requires an applicant to pursue a certificate renewal if the applicant does not begin construction within two years after the date the Commission grants the certificate. Dominion stated that “the timeframe of two years for renewal of a CPCN may be better at three years or greater. The Company’s concern is that some permits take so long to obtain that if the certificate expires there could be additional delays of another 2 years to "'re-obtain'" various permits."

NCSEA

NCSEA makes several recommendations. The first relates to the existing filing requirements for small power producer CPCN applications and renewable energy registrations. NCSEA notes that both Rule R8-64(b)(2) and R8-66(b)(1)(iii) require the applicant to provide the facility's "projected dependable capacity." NCSEA states that it appears that renewable energy project developers are construing the phrase differently, depending on whether they are filing for a CPCN or registering as a renewable energy facility. NCSEA stated that when owners are registering renewable energy facilities that have intermittent capacity (wind and solar), they frequently interpret the phrase "projected dependable capacity" to mean "projected dispatchable capacity." For non-dispatchable projects, owners are frequently reporting zero "projected dependable capacity." In contrast, developers of wind and solar projects that apply for a CPCN frequently interpret "projected dependable capacity" to mean "maximum nameplate capacity," according to NCSEA. Subsequently, applicants are providing the additional, more detailed information required under Rule R8-64 when a project's nameplate capacity is more than 5 MW.

NCSEA, therefore, recommends that the Commission revise Rule R8-64(b)(2) so that it conforms to current practice by replacing the phrase "projected dependable capacity" with the phrase "maximum nameplate capacity."

NCSEA notes that the Commission's current CPCN rules for merchant plants allow developers to designate some information as confidential. Rule R8-63(c) states:

> Confidential Information. If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

NCSEA recommends that the Commission add this same provision to Rule R8-64, the rule addressing CPCN applications for small power producers and co-generators.

NCSEA recommends a revision to the notice provision of Rule R8-64(c)(1), which currently states:

> The Commission will issue an order requiring the applicant to publish notice of the application once a week for four successive weeks in a daily newspaper of general circulation in the county where the generating facility is proposed to be constructed …

NCSEA notes that in many parts of the State, local daily newspapers of general circulation no longer exist, and that the General Assembly revised G.S. 62-82(a) during its 2013 session (Session Law 2013-410, Section 29) to remove the word "daily" from a parallel statutory requirement. NCSEA recommends that the Commission similarly remove the word "daily" from R8-64(c)(1).

NCSEA recommends that the Commission no longer require small power producer and co-generation facility developers to provide 12 copies of their applications, if the developer makes its filing electronically. Finally, NCSEA states that the current Rule R8-64 requires CPCN applications for small power producers and co-generators to include "a detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year." NCSEA recommends that the Commission's rules be amended such that applicants would be required to state "the specific on-peak and off-peak hours underlying the applicant's quantification of anticipated kilowatt and kilowatt-hour outputs."

Public Staff

The Public Staff provides a "redline" of many minor but useful changes. In addition, the Public Staff proposes several substantive changes. First, the Public Staff suggests the following amendment to Rule R8-64 (CPCNs for small power producers and co-generators):

> In addition to the information required above, an applicant who desires to enter into a contract for a term of 5 years or more for the sale of electricity and who will have a projected dependable capacity of 5 megawatts or more available for such sale or construct a solar photovoltaic facility with an alternating current (AC) capacity of 25 megawatts or greater shall include in the application the following three additional exhibits:[1]

NCSEA also references this rule provision via a footnote:

> If the Commission is interested in making substantive changes, it could consider increasing the threshold to 10 or 20 megawatts. Some of NCSEA's members have

[1] These three exhibits require an applicant to file:

1. A statement detailing the experience and expertise of the persons who will develop, design, construct and operate the project to the extent such persons are known at the time of the application.
2. Information specifically identifying the extent to which any regulated utility will be involved in the actual operation of the project.
3. A statement obtained by the applicant from the electric utility to which the applicant plans to sell the electricity to be generated setting forth an assessment of the impact of such purchased power on the utility's capacity, reserves, generation mix, capacity expansion plan, and avoided costs.
4. The most current available balance sheet of the applicant.
5. The most current available income statement of the applicant.
6. An economic feasibility study of the project.
7. A statement of the actual financing arrangements entered into in connection with the project to the extent known at the time of the application.
8. A detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year.
9. A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser.
10. A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

> suggested that this might be an appropriate revision given the evolving North Carolina marketplace. Such a change would streamline more filings and, in turn, reduce the time spent by the clerk's office reviewing filings to ensure all exhibits are attached and rule-compliant.

Further, the Public Staff recommends that Rule R8-64 be amended so that each electric utility would be required to "provide on its website a mailing address to which the application and notice should be mailed." The Public Staff also recommends that Rule R8-64 be amended so that:

> If the applicant does not file the affidavit of publication and certificate of service within six months of the Commission's publication order, the Commission will automatically dismiss the application.

The Public Staff does not provide an explanation for this proposed change. The Public Staff recommended amending Rules R8-63 and 64 to clarify that applicants should provide the size of their proposed facilities in terms of megawatts of "alternating current." The Public Staff also proposed to delete the annual progress reports required in Rule R8-64, "consistent with the comments filed by the Public Staff on July 29, 2014 in Docket No. E-100, Sub 113 that interconnection and construction progress reports should be filed by the utilities…."

The Public Staff recommends that, because CPCN applications for small power producers and co-generators under Rule R8-64 are not required to be filed by a member of the Bar of the State of North Carolina, the Commission should adopt an application form for this rule, as well as for Rule R8-65 (Report by Persons Constructing Electric Generating Facilities Exempt from Certification Requirements) and R8-66 (Registration of Renewable Energy Facilities; Annual Filing Requirements). In addition, the Public Staff recommends that the Commission merge the requirements of Rules R8-64 and 65 so that a facility owner "can seek the benefits of R8-66 and 64 or 65 with one application."

DISCUSSION AND CONCLUSIONS

The Commission has carefully considered the Public Gas Systems' recommendation that all new gas-fueled electric generation facilities be required to secure long-term firm gas supplies and pipeline capacity. While at first blush this recommendation appears to have merit, the Commission notes that the Public Gas Systems appear to be criticizing electric generators for engaging in gas purchasing practices that they themselves also follow. Specifically, purchasing gas and pipeline capacity on the spot market when "absolutely necessary" because of extreme weather events that were not contemplated and which do not occur often. Second, some gas-fired electric generators are peaking plants, and might only be needed to serve customers during the summer when air conditioning use is high. At such times, gas capacity tends to be available, even on the spot market. The fuel procurement practices for an electric generating plant should mirror the role that the plant will play in the public utility's fleet of plants. It might not be necessary for every natural gas-fired plant to have 20-year firm supply and pipeline capacity commitments. The rule changes that the Commission proposed in its September 8, 2014 Order include new requirements for electric public utilities to include in their CPCN applications:

> A statement of how the facility would contribute to resource and fuel diversity, whether the facility would have dual-fuel capability, and how much fuel would be stored at the site.

They would also be subject to this new requirement:

> In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated gas facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity …

The Commission concludes that these new provisions should be adequate to ensure that fuel supply issues are thoroughly discussed during the CPCN process for new electric generators. In addition, if the Commission were to adopt the Public Gas Systems' recommendation, there is a real possibility that electric utilities and their customers would be paying more and the Public Gas Systems and their customers would be paying less for pipeline capacity than is fair. It is the responsibility of the Public Gas Systems to ensure that there is adequate pipeline capacity available to serve their firm, heat-sensitive customers, even on the coldest of days. The Public Gas Systems should not rely on the Commission to order electric utilities to contract for excess gas pipeline capacity, which would result in additional costs being passed onto utility electric ratepayers to the benefit of Public Gas Systems' customers. Therefore, the Commission will decline to adopt the Public Gas Systems' recommendation that all new gas-fueled electric generation facilities be required to secure long-term firm gas supplies and pipeline capacity.

Regarding Dominion's suggestion that the deadline for beginning construction pursuant to a CPCN be extended from the current two years to three years for merchant developers, the Commission finds this suggestion to be reasonable given the complexities of securing all of the permits needed for a generating facility, and will adopt Dominion's recommendation. As to Dominion's concerns regarding an applicant's obligation to file financial information, the changes being approved today would actually ease that requirement somewhat. Today, applicants seeking approval for a plant of 300 MW or more must file financial information 120 days in advance of their CPCN application. Under the changes approved today, that information would become part of the CPCN application itself.

The Commission carefully considered the recommendations made by NCSEA. NCSEA suggests amending Rule R8-64(b)(2) so that applicants would be reporting their "maximum nameplate capacity." The Commission finds that it would be instructive and helpful to have a proposed facility's capacity reported both in terms of maximum nameplate capacity and in terms of projected dependable capacity, as the rule requires today. The Commission will, therefore, add that requirement and clarify that applicants should provide the information as megawatts alternating current, as discussed below.

The Commission agrees with NCSEA's recommendation that would allow small power producers and co-generators to designate some information as confidential, as well as its suggestion to remove the requirement to provide notice via a daily newspaper. The Commission will adopt those proposed changes. NCSEA's recommendation that these applicants also be relieved of filing paper copies if they file electronically is unnecessary. Commission Rule R1-28(b) provides that, with limited exceptions, those making electronic filings do not need to also file paper copies. Finally, NCSEA recommends that Rule R8-64 be amended so that applicants include the specific hours that they consider to be on-peak and off-peak. The Commission finds that this recommendation has merit and will adopt it.

The Commission has reviewed the comments as well as the proposed rule changes submitted by the Public Staff. The Public Staff provides many minor but useful edits that the Commission will adopt. In addition, the Public Staff proposed several substantive changes. In terms of the Public Staff's proposal to raise the threshold in Rule R8-64(b)(2) that triggers the need for solar photovoltaic developers to file additional information, the Commission supports this change and agrees with NCSEA that such a change would streamline the process. However, the Commission will re-word the change somewhat to be more clear, as shown below:

> ~~In addition to the information required above,~~ A~~a~~n applicant who desires to enter into a contract for ~~a term of~~ 5 years or more for the sale of electricity, ~~and~~ whose facility will have a ~~projected dependable~~ nameplate capacity of 5 megawatts alternating current or more, and whose facility is not a solar photovoltaic facility, ~~available for such sale~~shall include in the application ~~the following information and~~ three additional exhibits~~:~~ as described in R8-64(b)(6)(i), (ii), and (iii) below, except that an applicant who desires to enter into a contract of 5 years or more for the sale of electricity from a solar photovoltaic facility of 25 megawatts alternating current or more shall also include the three additional exhibits referenced herein.

The Public Staff recommended amending Rules R8-63 and 64 to clarify that applicants should provide the size of their proposed facilities in terms of megawatts of "alternating current." The Commission will adopt those changes but also seeks comments as to whether it would be preferable to instead amend Commission Rule R8-2, so that all capacity reporting under Rule R8 (Electric Light & Power) would be in terms of alternating current, as shown below:

> **Rule R8-2. DEFINITIONS.**
>
> In the interpretation of these rules the word "utility" shall be taken to mean any person, firm or corporation engaged in the business of supplying electric current to domestic, commercial, or industrial users within this State except a municipality or electric membership corporation organized under G.S. 117-6 et seq. and the word "consumer" shall be taken to mean any person, firm, corporation, municipality, or other political subdivision of the State supplied by any such utility. Unless specifically stated otherwise, capacity of generation facilities is provided in alternating current (AC) delivered at the point of interconnection to the distribution or transmission facilities.

The Public Staff submits substantial changes to Rules R8-65 and R8-66, which are beyond the scope of the Commission's September 8, 2014 Order. Therefore, the Commission will ask the Public Staff to file additional information explaining the need for these changes. The Commission specifically welcomes the Public Staff providing more information on how the requirements of

Rules R8-64 and 65 could be "merged." The Public Staff is also invited to file additional information as to the need to dismiss applications under Rule R8-64 after six months if an applicant has not yet filed its affidavit showing publication of notice.

Finally, the Public Staff proposes to delete the annual progress reports required in Rule R8-64(e). The Commission will decline to address that issue in this proceeding, as it is pending in Docket No. E-100, Sub 113.

IT IS, THEREFORE, ORDERED as follows:

1. That, consistent with the findings in this Order and as provided in Appendix A (black-lined) and Appendix B (changes incorporated), the Commission hereby amends Rules R8-61, 63 and 64, effective January 1, 2015;

2. That the Public Staff is requested to file an explanation of its proposed changes to Rules R8-65 and 66, on or before December 15, 2014;

3. That other parties may also propose changes to Rules R8-65 and 66 on or before December 15, 2014;

4. That all parties are invited to comment on the Commission's proposal to amend Rule R8-2 on or before December 15, 2014; and

5. That Parties may file reply comments on or before January 16, 2015.

ISSUED BY ORDER OF THE COMMISSION
This the _4th_ day of November, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A
PAGE 1 of 13

Rule R8-61. PRELIMINARY PLANS AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION OF ELECTRIC GENERATION AND RELATED TRANSMISSION FACILITIES IN NORTH CAROLINA; CONSTRUCTION OF OUT-OF-STATE ELECTRIC GENERATING FACILITIES; PROGRESS REPORTS AND ONGOING REVIEWS OF CONSTRUCTION; PROJECT DEVELOPMENT COST REVIEWS FOR NUCLEAR GENERATING FACILITIES.

(a) A public utility or other person that plans to build an electricity generating facility with a nameplate capacity of 300 megawatts (alternating current) or more shall file with the Commission and the Department of the Environment and Natural Resources its preliminary plans ~~Information~~ ~~to be filed~~ at least 120 ~~or more~~ days before ~~the~~ filing ~~of~~ an application~~, by a public utility or other person,~~ for a certificate of public convenience and necessity. The preliminary plans ~~for generating facilities with capacity of 300 MW or more~~ shall include the following exhibits:

(1) Exhibit 1 shall contain the following site information:
(i) ~~Available site information (including~~ A color map~~s~~ or aerial photo (a U.S. Geological Survey map or an aerial photo map prepared via the State's geographic information system is preferred) ~~and description), preliminary estimates of initial and ultimate development, a drawing~~ showing the proposed site boundary and layout ~~relative to the map~~, with all major equipment, including the generator, fuel handling equipment, plant distribution system, startup equipment, ~~site boundary,~~ planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities;

~~(2)~~ (ii) The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree;
(iii) The full and correct name of the site owner and, if the owner is other than the applicant, the applicant's interest in the site;
(iv) Justification for the adoption of the site selected, and general information describing the other locations considered;

~~(3)~~ (v) ~~As appropriate, preliminary~~ ~~i~~Information concerning geological, aesthetic, ecological, meteorological, seismic, water supply, and local population ~~and general load center data to the extent known~~;

~~(4)~~ ~~A statement of the need for the facility, including information on loads and generating capability;~~

~~(5)~~ (vi) A description of investigations completed, in progress, or proposed involving the subject site;

~~(6)~~ (vii) A statement of existing or proposed plans known to the applicant of federal, state, local governmental and private entities for other developments at or adjacent to the proposed site;

APPENDIX A
PAGE 2 of 13

~~(7)~~ ~~A statement of existing or proposed environmental evaluation programs to meet the applicable air and water quality standards;~~
(viii) In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated gas facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

(ix) A brief general description of practicable transmission line routes emanating from the site, including a color map showing their general location; and
(x) The gross, net, and nameplate generating capacity of each unit and the entire facility's total projected dependable capacity in alternating current (AC).

(2) Exhibit 2 shall contain the following permitting information:

(i~~9~~) A list of all agencies from which approvals will be sought covering various aspects of any generation facility constructed on the site and the title and nature of such approvals; and
~~(10) A statement of estimated cost information, including plans and related transmission capital cost (initial core costs for nuclear units); all operating expenses by categories, including fuel costs and total generating cost per net kWh at plant; and information concerning capacity factor, heat rate, and plant service life. Furnish comparative cost including related transmission cost of other final alternatives considered; and~~

(ii) A statement of existing or proposed environmental evaluation programs to meet the applicable air and water quality standards.

(3) Exhibit 3 shall include a:
~~(11) A~~ schedule showing the anticipated beginning dates for construction, testing, and commercial operation of the generating facility.

(b) In filing an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) in order to construct a generating facility in North Carolina, a public utility shall include the following ~~information~~ exhibits supported by relevant testimony:

(1) Exhibit 1 shall contain the following resource planning information:

(i~~1~~) The utility's most recent biennial report and the most recent annual report ~~(as defined in~~ filed pursuant to Rule R8-60~~)~~, ~~of the utility~~ plus any proposals by the utility to update said reports;
(ii~~2~~) The extent to which the proposed ~~construction~~ facility would conform~~s~~ to the utility's most recent biennial report and the most recent annual report ~~(as defined in~~ that was filed pursuant to Rule R8-60~~)~~;
(iii~~3~~) A statement of how the facility would contribute to resource and fuel diversity, whether the facility would have dual-fuel capability, and how much fuel would be stored at the site. ~~Support for any utility proposals to~~

APPENDIX A
PAGE 3 of 13

~~update its most recent biennial report and its most recent annual report (as defined in Rule R8-60);~~
(iv) An explanation of the need for the facility, including information on energy and capacity forecasts; and

(v) An explanation of how the proposed facility meets the identified energy and capacity needs, including the anticipated facility capacity factor, heat rate, and service life.

(2) Exhibit 2 shall contain
~~(4)~~ ~~Updates, if any, to~~ the siting and permitting information as listed in Rule R8-61(a) ~~information;~~, with updates as necessary for facilities that are 300 megawatts (alternating current) nameplate capacity or more, and for which this information had already been filed.

(3) Exhibit 3 shall contain the following cost information for the proposed facility, and for the final alternatives that the applicant considered:

(i~~5~~) An estimate of the construction costs for the generating facility, including the costs for new substation(s) and transmission line(s), and upgrades to existing substations(s) and transmission lines(s). For nuclear plants, construction costs shall include the plant's first core fuel load;
(ii) Estimated construction costs expressed as dollars per megawatt of capacity;
(iii) Estimated annual operating expenses by category, including fuel costs;
(iv) Estimated annual operating expenses expressed as dollars per net megawatt-hour.
(v~~6~~) The projected cost of each major component of the generating facility and the projected schedule for incurring those costs;
(vi~~7~~) The projected effect of investment in the generating facility on the utility's overall revenue requirement for each year during the construction period;
(vii) The anticipated in-service expenses associated with the generating facility for the 12-month period of time following commencement of commercial operation of the facility; and
(viii) The anticipated impact the facility will have on customer rates.

(4) Exhibit 4 shall contain the following construction information:

i. ~~(8)~~ The anticipated construction schedule for the generating facility;
ii. ~~(9)~~ The specific type of units selected for the generating facility; the suppliers of the major components of the facility; the basis for selecting the type of units, major components, and suppliers; and arrangements made or planned to assure a dependable ~~the adequacy of~~ fuel supply;
iii.~~(10)~~The qualifications and selection process of principal contractors and suppliers for construction of the generating facility, other than those listed in Item (~~9~~ii) above; and

~~(11) Resource and fuel diversity and reasonably anticipated future operating costs, including the anticipated in-service expenses associated with the generating facility for the 12-month period of time following commencement of commercial operation of the facility;~~

iv.~~(12)~~ Risk factors related to the construction and operation of the generating facility, including a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located~~; and~~.

(5) If the facility is a coal or nuclear-fueled facility, the application shall include Exhibit 5, which shall contain

~~(13) If the application is for a coal or nuclear generating facility,~~ information demonstrating that energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof, would not establish or maintain a more cost-effective and reliable generation system and that the construction and operation of the facility is in the public interest.

(c) The public utility shall submit a progress report and any revision in the construction cost estimate during each year of construction according to a schedule established by the Commission.

(d) Upon the request of the public utility or upon the Commission's own motion, the Commission may conduct an ongoing review of construction of the generating facility as the construction proceeds.

(e) A public utility requesting an ongoing review of construction of the generating facility pursuant to G.S. 62-110.1(f) shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity by the Commission; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause. Upon the filing of a request for an ongoing review, the Commission shall establish a schedule of hearings. The hearings shall be held no more often than every 12 months. The Commission shall also establish the time period to be reviewed during each hearing. The purpose of each ongoing review hearing is to determine the reasonableness and prudence of the costs incurred by the public utility during the period under review and to determine whether the certificate should remain in effect or be modified or revoked. The public utility shall have the burden of proof to demonstrate that all costs incurred are reasonable and prudent.

(f) A public utility may file an application pursuant to G.S. 62-110.6 requesting the Commission to determine the need for an out-of-state electric generating facility that is intended to serve retail customers in North Carolina. If need for the generating facility is

established, the Commission shall also approve an estimate of the construction costs and construction schedule for such facility. The application may be filed at any time after an application for a certificate of public convenience and necessity or license for construction of the generating facility has been filed in the state in which the facility will be sited. The application shall be supported by relevant testimony and shall include the information required by subsection (b) of this Rule to the extent such information is relevant to the showing of need for the generating facility and the estimated construction costs and proposed construction schedule for the generating facility. The public utility shall submit a progress report and any revision in the construction cost estimate for the out-of-state electric generating facility during each year of construction according to a schedule established by the Commission.

(g) If the Commission makes a determination of need pursuant to G.S. 62-110.6 and subsection (f) of this Rule, the provisions of subsections (d) and (e) of this Rule shall apply to a request by a public utility for an ongoing review of construction of a generating facility to be constructed in another state that is intended to serve retail customers in North Carolina. An electric public utility shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity or license by the state commission in which the out-of-state generating facility is to be constructed; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause.

(h) A public utility may file an application pursuant to G.S. 62-110.7 requesting the Commission to review the public utility's decision to incur project development costs for a potential in-state or out-of-state nuclear generating facility that is intended to serve retail electric customers in North Carolina. The application, supported by relevant testimony, shall be filed prior to the filing of an application for a certificate to construct the facility.

Rule R8-63. APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR MERCHANT PLANT; PROGRESS REPORTS.

(a) Scope of Rule.

(1) This rule applies to an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) by any person seeking to construct a merchant plant in North Carolina.

(2) For purposes of this rule, the term "merchant plant" means an electric generating facility, other than one that qualifies for and seeks the benefits of 16 U.S.C.A. 824a-3 or G.S. 62-156, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility pursuant to G.S. 62-133.

(3) Persons filing under this rule are not subject to the requirements of Rule ~~R1-37 or Rule~~ R8-61 <u>or R8-64</u>.

(b) Application.

~~(1)~~ The application shall contain ~~all of~~ the exhibits listed below, which shall contain the information hereinafter required, with each exhibit and item labeled as set out below. Any additional information may be included at the end of the application.

(1) Exhibit 1 shall contain the following information about t~~T~~he a~~A~~pplicant:

(i) The full and correct name, business address, ~~and~~ business telephone number and electronic mailing address of the applicant;

(ii) A description of the applicant, including the identities of its principal participant(s) and officers, and the name and business address of a person authorized to act as corporate agent or to whom correspondence should be directed; ~~and~~

(iii) A copy of the applicant's most recent annual report to stockholders, which may be attached as an exhibit, or, if the applicant is not publicly traded, its most recent balance sheet and income statement. If the applicant is a newly formed entity with little history, this information should be provided for its parent company, equity partner, and/or the other participant(s) in the project~~.~~; and

(iv) Information about generating facilities in the Southeastern Electric Reliability Council region which the applicant or an affiliate has any ownership interest in and/or the ability to control through leases, contracts, options, and/or other arrangements and information about certificates that have been granted for any such facilities not yet constructed.

(2) Exhibit 2 shall contain the following information about t~~T~~he proposed f~~F~~acility:

(i) The nature of the proposed generating facility, including its type, fuel, ~~size, and~~ expected service life, and the gross, net, and nameplate generating capacity of each generating unit and the entire facility, as well as the facility's total projected dependable capacity, in megawatts (alternating current); the anticipated beginning date for construction; the expected commercial operation date; and estimated construction costs;

(ii) A ~~detailed description of the location of the generating facility, including a~~ color map or aerial photo (a U.S. Geological Survey map or aerial photo map prepared via the State's geographic information system is preferred) showing the ~~with the location marked;~~

~~(iii) A drawing showing the~~ proposed site boundary and layout ~~relative to the map provided pursuant to (B)(ii)~~, with all major equipment, including the generator, fuel handling equipment, plant distribution system, startup equipment, ~~site boundary,~~

planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities;

(iii) The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree.

(iv) In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

(v) A list of all needed federal, state, and local approvals related to the facility and site, identified by title and the nature of the needed approval; a copy of such approvals or a report of their status; and a copy of any application related to eligible facility and/or exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (PUHCA), as amended by the Energy Policy Act of 1992, including attachments and subsequent amendments, if any; and

(vi) A ~~general~~ description of the transmission facilities to which the facility will interconnect, and a color map showing their general location. If additional facilities are needed, a statement regarding ~~have access or~~ whether the applicant would need to ~~necessity of~~ acquir~~ing~~e rights-of-way for new facilities~~; and~~.

~~(vii) Information about generating facilities in the Southeastern Electric Reliability Council region which the applicant or an affiliate has any ownership interest in and/or the ability to control through leases, contracts, options, and/or other arrangements and information about certificates that have been granted for any such facilities not yet constructed.~~

(~~C~~3) ~~Statement of Need: A~~ Exhibit 3 shall provide a description of the need for the facility in the state and/or region, with supporting documentation.

(~~2~~4) The application shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant.

(~~3~~5) The application shall be accompanied by prefiled direct testimony incorporating and supporting the application.

(~~4~~6) The Chief Clerk will deliver ~~ten (10) copies~~ a copy of the application to the Clearinghouse Coordinator in the Department of Administration for distribution to State agencies having an interest in the proposed generating facility.

(~~5~~7) Contemporaneous with the filing of the application with the Commission, all applicants proposing a generating facility that will use natural gas must provide written notice of the filing to the natural gas local distribution

company or municipal gas system providing service or franchised to provide service at the location of the proposed generating facility.

(c) Confidential Information. If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

(d) Procedure upon Receipt of Application. No later than ten (10) business days after the application is filed with the Commission, the Public Staff shall, and any other party in interest may, file with the Commission and serve upon the applicant a notice regarding whether the application is complete and identifying any deficiencies. If the Commission determines that the application is not complete, the applicant will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue a procedural order setting the matter for hearing, requiring public notice, and dealing with other procedural matters.

(e) The Certificate.

(1) The certificate shall specify the name and address of the certificate holder; the type, ~~size~~ capacity, and location of the facility; and the conditions, if any, upon which the certificate is granted.

(2) The certificate shall be subject to revocation if (a) any of the federal, state, or local licenses or permits required for construction and operation of the generating facility ~~is are~~ not obtained or, having been obtained, ~~is~~ are revoked pursuant to a final, non-appealable order; (b) required reports or fees are not filed with or paid to the Commission; and/or (c) the Commission concludes that the certificate holder filed with the Commission information of a material nature that was inaccurate and/or misleading at the time it was filed; provided that, prior to revocation pursuant to any of the foregoing provisions, the certificate holder shall be given thirty (30) days' written notice and opportunity to cure.

(3) The certificate must be renewed if the applicant does not begin construction within ~~two~~ three years after the date of the Commission order granting the certificate.

(4) A certificate holder must notify the Commission in writing of any plans to sell, transfer, or assign the certificate and the generating facility.

(f) Reporting. All applicants must submit annual progress reports and any revisions in cost estimates, as required by G.S. 62-110.1(f) until construction is completed.

R8-64 APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY BY QUALIFYING COGENERATOR OR SMALL POWER PRODUCER; PROGRESS REPORTS.

(a) Scope of Rule.

(1) This rule applies to applications for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) filed by any person seeking the benefits of 16 U.S.C. 824a-3 or G.S. 62-156 as a qualifying cogenerator or

a qualifying small power producer as defined in 16 U.S.C. 796(17) and (18) or as a small power producer as defined in G.S. 62-3(27a), except persons exempt from certification by the provisions of G.S. 62-110.1(g).

(2) For purposes of this rule, the term "person" shall include a municipality as defined in Rules R7-2(c) and R10-2(c), including a county of the State.

(3) The construction of a facility for the generation of electricity shall include not only the building of a new building, structure or generator, but also the renovation or reworking of an existing building, structure or generator in order to enable it to operate as a generating facility.

(4) This rule shall apply to any person within its scope who begins construction of an electric generating facility without first obtaining a certificate of public convenience and necessity. In such circumstances, the application shall include an explanation for the applicant's beginning of construction before the obtaining of the certificate.

(b) The Application.

~~(1)~~ The application shall be ~~accompanied by maps, plans, and specifications setting forth such details and dimensions as the Commission requires. It shall contain, among other things, the following information, either embodied in the application or attached thereto as~~ <u>comprised of the following five exhibits</u>:

<u>(1) Exhibit 1 shall contain:</u>

(i) The full and correct name, business address, business telephone number, and electronic mailing address of the facility owner;

(ii) A statement of whether the facility owner is an individual, a partnership, or a corporation and, if a partnership, the name and business address of each general partner and, if a corporation, the state and date of incorporation and the name, business address, business telephone number, and electronic mailing address of an individual duly authorized to act as corporate agent for the purpose of the application and, if a foreign corporation, whether domesticated in North Carolina; <u>and</u>

(iii) <u>The full and correct name of the site owner and, if the owner is other than the applicant, the applicant's interest in the site.</u> ~~;The nature of the generating facility, including the type and source of its power or fuel;~~

(2) Exhibit 2 shall contain:

(i~~v~~) A color map or aerial photo showing ~~T~~the location of the generating facility site in relation to ~~set forth in terms of~~ local highways, streets, rivers, streams, ~~or~~ and other generally known local landmarks, ~~together with a map, such as a county road map,~~ with the proposed location of major equipment indicated on the map or photo~~map~~, including: ~~; and a drawing showing: (1) the proposed site layout relative to the map; (2) all major equipment, including~~ the generator,

fuel handling equipment, plant distribution system, ~~and~~ startup equipment,~~;~~ ~~(3)~~ the site boundary,~~; and (4)~~ planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities~~;~~. A U.S. Geological Survey map or an aerial photo map prepared via the State's geographic information system is preferred; and

~~(v)~~ ~~The ownership of the site and, if the owner is other than the applicant, the applicant's interest in the site;~~

(ii) The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree.

(3) Exhibit 3 shall contain:

(i) The nature of the generating facility, including the type and source of its power or fuel;

(~~v~~ii) A description of the buildings, structures and equipment comprising the generating facility and the manner of its operation;

(~~v~~iii) The gross and net projected maximum dependable capacity of the facility ~~in megawatts~~, as well as the facility's nameplate capacity, expressed as megawatts (alternating current);

~~(viii)~~ ~~The projected cost of the facility;~~

(iv~~ix~~) The projected date on which the facility will come on line; and

(v~~x~~) The applicant's general plan for sale of the electricity to be generated, including the utility to which the applicant plans to sell the electricity;

(vi) A~~a~~ny provisions for wheeling of the electricity;

(vii) A~~a~~rrangements for firm, non-firm or emergency generation;

(viii) T~~t~~he service life of the project;

(ix) T~~t~~he projected annual sales in kilowatt-hours; and

(x) W~~w~~hether the applicant intends to produce renewable energy certificates that are eligible for compliance with the State's renewable energy and energy efficiency portfolio standard. ~~; and~~

(4) Exhibit 4 shall contain:

(i~~xi~~) A complete list of all federal and state licenses, permits and exemptions required for construction and operation of the generating facility and a statement of whether each has been obtained or applied for.

(ii) A copy of those that have been obtained should be filed with the application; a copy of those that have not been obtained at the time of the application should be filed with the Commission as soon as they are obtained.

(5) Exhibit 5 shall contain the expected cost of the proposed facility.

(~~2~~6) ~~In addition to the information required above,~~ A~~a~~n applicant who desires to enter into a contract for ~~a term of~~ 5 years or more for the sale of electricity, ~~and~~ whose facility will have a ~~projected dependable~~ nameplate capacity of 5 megawatts alternating current or more, and whose facility is not a solar photovoltaic facility, ~~available for such sale~~shall include in the application ~~the following information and~~ three additional exhibits~~:~~ as described in R8-64(b)(6)(i), (ii), and (iii) below, except that an applicant who desires to enter into a contract of 5 years or more for the sale of electricity from a solar photovoltaic facility of 25 megawatts alternating current or more shall also include the three additional exhibits referenced herein.

(i) Exhibit 6 shall contain:

~~(i)~~a A statement detailing the experience and expertise of the persons who will develop, design, construct and operate the project to the extent such persons are known at the time of the application;

~~(ii)~~b Information specifically identifying the extent to which any regulated utility will be involved in the actual operation of the project; and

~~(iii)~~c A statement obtained by the applicant from the electric utility to which the applicant plans to sell the electricity to be generated setting forth an assessment of the impact of such purchased power on the utility's capacity, reserves, generation mix, capacity expansion plan, and avoided costs~~;~~.

(ii) Exhibit 7 shall contain:

~~(iv)~~a The most current available balance sheet of the applicant;

~~(v)~~b The most current available income statement of the applicant;

~~(vi)~~c An economic feasibility study of the project; and

~~(vii)~~d A statement of the actual financing arrangements entered into in connection with the project to the extent known at the time of the application~~;~~.

(iii) Exhibit 8 shall contain:

~~(viii)~~a A detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year. The explanation shall include a statement of the specific on-peak and off-peak hours underlying the applicant's quantification of anticipated kilowatt and kilowatt-hour outputs;

~~(ix)~~b A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser; and

~~(x)~~c A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

(~~3~~7) All applications shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant for the purpose of the application.

(~~4~~8) Applications filed on behalf of a corporation are not subject to the provision of R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(~~5~~9) Falsification of or failure to disclose any required information in the application may be grounds for denying or revoking any certificate.

(~~6~~10) The application and 12 copies shall be filed with the Chief Clerk of the Utilities Commission.

(11) If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

(c) Procedure upon receipt of Application. — Upon the filing of an application appearing to meet the requirements set forth above, the Commission will process it as follows:

(1) The Commission will issue an order requiring the applicant to publish notice of the application once a week for four successive weeks in a ~~daily~~ newspaper of general circulation in the county where the generating facility is proposed to be constructed and requiring the applicant to mail a copy of the application and the notice, no later than the first date that such notice is published, to the electric utility to which the applicant plans to sell the electricity to be generated. Each electric utility shall provide on its website a mailing address to which the application and notice should be mailed. The applicant shall be responsible for filing with the Commission an affidavit of publication and a signed and verified certificate of service to the effect that the application and notice have been mailed to the electric utility to which the applicant plans to sell the electricity to be generated.

(2) The Chief Clerk will deliver 2 copies of the application and the notice to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the application.

(3) If a complaint is received within 10 days after the last date of the publication of the notice, the Commission will schedule a public hearing to determine whether a certificate should be awarded and will give reasonable notice of the time and place of the hearing to the applicant and to each complaining party and will require the applicant to publish notice of the hearing in the newspaper in which the notice of the application was published. If no complaint is received within the time specified, the Commission may, upon its own initiative, order and schedule a hearing to determine whether a certificate should be awarded and, if the Commission

orders a hearing upon its own initiative, it will require notice of the hearing to be published by the applicant in the newspaper in which the notice of the application was published.

(4) If no complaint is received within the time specified and the Commission does not order a hearing upon its own initiative, the Commission will enter an order awarding the certificate.

(d) The Certificate.

(1) The certificate shall be subject to revocation if any of the other federal or state licenses, permits or exemptions required for construction and operation of the generating facility is not obtained and that fact is brought to the attention of the Commission and the Commission finds that as a result the public convenience and necessity no longer requires, or will require, construction of the facility.

(2) The certificate must be renewed by re-compliance with the requirements set forth in this Rule if the applicant does not begin construction within 5 years after issuance of the certificate.

(3) Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or assign the certificate or the generating facility or of any significant changes in the information set forth in subsection (b)(1) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes.

(e) Reporting. — All applicants must submit annual progress reports until construction is completed.

Rule R8-61. PRELIMINARY PLANS AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION OF ELECTRIC GENERATION AND RELATED TRANSMISSION FACILITIES IN NORTH CAROLINA; CONSTRUCTION OF OUT-OF-STATE ELECTRIC GENERATING FACILITIES; PROGRESS REPORTS AND ONGOING REVIEWS OF

CONSTRUCTION; PROJECT DEVELOPMENT COST REVIEWS FOR NUCLEAR GENERATING FACILITIES.

(a) A public utility or other person that plans to build an electricity generating facility with a nameplate capacity of 300 megawatts (alternating current) or more shall file with the Commission and the Department of the Environment and Natural Resources its preliminary plans at least 120 days before filing an application for a certificate of public convenience and necessity. The preliminary plans shall include the following exhibits:

(1) Exhibit 1 shall contain the following site information:

(i) A color map or aerial photo (a U.S. Geological Survey map or an aerial photo map prepared via the State's geographic information system is preferred) showing the proposed site boundary and layout, with all major equipment, including the generator, fuel handling equipment, plant distribution system, startup equipment, planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities;

(ii) The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree;

(iii) The full and correct name of the site owner and, if the owner is other than the applicant, the applicant's interest in the site;

(iv) Justification for the adoption of the site selected, and general information describing the other locations considered;

(v) Information concerning geological, aesthetic, ecological, meteorological, seismic, water supply, and local population;

(vi) A description of investigations completed, in progress, or proposed involving the subject site;

(vii) A statement of existing or proposed plans known to the applicant of federal, state, local governmental and private entities for other developments at or adjacent to the proposed site;

(viii) In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated gas facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

(ix) A brief general description of practicable transmission line routes emanating from the site, including a color map showing their general location; and

APPENDIX B
PAGE 2 of 12

(x) The gross, net, and nameplate generating capacity of each unit and the entire facility's total projected dependable capacity in alternating current (AC).

(2) Exhibit 2 shall contain the following permitting information:

(i) A list of all agencies from which approvals will be sought covering various aspects of any generation facility constructed on the site and the title and nature of such approvals; and

(ii) A statement of existing or proposed environmental evaluation programs to meet the applicable air and water quality standards.

(3) Exhibit 3 shall include a schedule showing the anticipated beginning dates for construction, testing, and commercial operation of the generating facility.

(b) In filing an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) in order to construct a generating facility in North Carolina, a public utility shall include the following exhibits supported by relevant testimony:

(1) Exhibit 1 shall contain the following resource planning information:

(i) The utility's most recent biennial report and the most recent annual report filed pursuant to Rule R8-60, plus any proposals by the utility to update said reports;

(ii) The extent to which the proposed facility would conform to the utility's most recent biennial report and the most recent annual report—that was filed pursuant to Rule R8-60;

(iii) A statement of how the facility would contribute to resource and fuel diversity, whether the facility would have dual-fuel capability, and how much fuel would be stored at the site.

(iv) An explanation of the need for the facility, including information on energy and capacity forecasts; and

(v) An explanation of how the proposed facility meets the identified energy and capacity needs, including the anticipated facility capacity factor, heat rate, and service life.

(2) Exhibit 2 shall contain the siting and permitting information as listed in Rule R8-61(a), with updates as necessary for facilities that are 300 megawatts (alternating current) nameplate capacity or more, and for which this information had already been filed.

(3) Exhibit 3 shall contain the following cost information for the proposed facility, and for the final alternatives that the applicant considered:

(i) An estimate of the construction costs for the generating facility, including the costs for new substation(s) and transmission line(s), and upgrades to existing substations(s) and transmission lines(s). For nuclear plants, construction costs shall include the plant's first core fuel load;

(ii) Estimated construction costs expressed as dollars per megawatt of capacity;
(iii) Estimated annual operating expenses by category, including fuel costs;
(iv) Estimated annual operating expenses expressed as dollars per net megawatt-hour.
(v) The projected cost of each major component of the generating facility and the projected schedule for incurring those costs;
(vi) The projected effect of investment in the generating facility on the utility's overall revenue requirement for each year during the construction period;
(vii) The anticipated in-service expenses associated with the generating facility for the 12-month period of time following commencement of commercial operation of the facility; and
(viii) The anticipated impact the facility will have on customer rates.

(4) Exhibit 4 shall contain the following construction information:
(i) The anticipated construction schedule for the generating facility;
(ii) The specific type of units selected for the generating facility; the suppliers of the major components of the facility; the basis for selecting the type of units, major components, and suppliers; and arrangements made or planned to assure a dependable fuel supply;
(iii) The qualifications and selection process of principal contractors and suppliers for construction of the generating facility, other than those listed in Item (ii) above; and
(iv) Risk factors related to the construction and operation of the generating facility, including a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located.

(5) If the facility is a coal or nuclear-fueled facility, the application shall include Exhibit 5, which shall contain information demonstrating that energy efficiency measures; demand-side management; renewable energy resource generation; combined heat and power generation; or any combination thereof, would not establish or maintain a more cost-effective and reliable generation system and that the construction and operation of the facility is in the public interest.

(c) The public utility shall submit a progress report and any revision in the construction cost estimate during each year of construction according to a schedule established by the Commission.

(d) Upon the request of the public utility or upon the Commission's own motion, the Commission may conduct an ongoing review of construction of the generating facility as the construction proceeds.

(e) A public utility requesting an ongoing review of construction of the generating facility pursuant to G.S. 62-110.1(f) shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity by the Commission; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause. Upon the filing of a request for an ongoing review, the Commission shall establish a schedule of hearings. The hearings shall be held no more often than every 12 months. The Commission shall also establish the time period to be reviewed during each hearing. The purpose of each ongoing review hearing is to determine the reasonableness and prudence of the costs incurred by the public utility during the period under review and to determine whether the certificate should remain in effect or be modified or revoked. The public utility shall have the burden of proof to demonstrate that all costs incurred are reasonable and prudent.

(f) A public utility may file an application pursuant to G.S. 62-110.6 requesting the Commission to determine the need for an out-of-state electric generating facility that is intended to serve retail customers in North Carolina. If need for the generating facility is established, the Commission shall also approve an estimate of the construction costs and construction schedule for such facility. The application may be filed at any time after an application for a certificate of public convenience and necessity or license for construction of the generating facility has been filed in the state in which the facility will be sited. The application shall be supported by relevant testimony and shall include the information required by subsection (b) of this Rule to the extent such information is relevant to the showing of need for the generating facility and the estimated construction costs and proposed construction schedule for the generating facility. The public utility shall submit a progress report and any revision in the construction cost estimate for the out-of-state electric generating facility during each year of construction according to a schedule established by the Commission.

(g) If the Commission makes a determination of need pursuant to G.S. 62-110.6 and subsection (f) of this Rule, the provisions of subsections (d) and (e) of this Rule shall apply to a request by a public utility for an ongoing review of construction of a generating facility to be constructed in another state that is intended to serve retail customers in North Carolina. An electric public utility shall file an application, supported by relevant testimony, for an ongoing review no later than 12 months after the date of issuance of a certificate of public convenience and necessity or license by the state commission in which the out-of-state generating facility is to be constructed; provided, however, that the public utility may, prior to the conclusion of such 12-month period, petition the Commission for a reasonable extension of time to file an application based on a showing of good cause.

(h) A public utility may file an application pursuant to G.S. 62-110.7 requesting the Commission to review the public utility's decision to incur project development costs for a potential in-state or out-of-state nuclear generating facility that is intended to serve retail electric customers in North Carolina. The application, supported by relevant testimony, shall be filed prior to the filing of an application for a certificate to construct the facility.

Rule R8-63. APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR MERCHANT PLANT; PROGRESS REPORTS.

(a) Scope of Rule.

(1) This rule applies to an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) by any person seeking to construct a merchant plant in North Carolina.

(2) For purposes of this rule, the term "merchant plant" means an electric generating facility, other than one that qualifies for and seeks the benefits of 16 U.S.C.A. 824a-3 or G.S. 62-156, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility pursuant to G.S. 62-133.

(3) Persons filing under this rule are not subject to the requirements of RuleR8-61 or R8-64.

(b) Application. The application shall contain the exhibits listed below, which shall contain the information hereinafter required, with each exhibit and item labeled as set out below. Any additional information may be included at the end of the application.

(1) Exhibit 1 shall contain the following information about the applicant:

(i) The full and correct name, business address, business telephone number and electronic mailing address of the applicant;

(ii) A description of the applicant, including the identities of its principal participant(s) and officers, and the name and business address of a person authorized to act as corporate agent or to whom correspondence should be directed; ~~and~~

(iii) A copy of the applicant's most recent annual report to stockholders, which may be attached as an exhibit, or, if the applicant is not publicly traded, its most recent balance sheet and income statement. If the applicant is a newly formed entity with little history, this information should be provided for its parent company, equity partner, and/or the other participant(s) in the project; and

(iv) Information about generating facilities in the Southeastern Electric Reliability Council region which the applicant or an affiliate has any ownership interest in and/or the ability to control through leases, contracts, options, and/or other arrangements and information about certificates that have been granted for any such facilities not yet constructed.

(2) Exhibit 2 shall contain the following information about the proposed facility:

(i) The nature of the proposed generating facility, including its type, fuel, expected service life, and the gross, net, and nameplate generating capacity of each generating unit and the entire facility, as well as the facility's total projected dependable capacity, in megawatts (alternating current); the anticipated beginning date for construction; the expected commercial operation date; and estimated construction costs;

(ii) A color map or aerial photo (a U.S. Geological Survey map or aerial photo map prepared via the State's geographic information system is preferred) showing the proposed site boundary and layout, with all major equipment, including the generator, fuel handling equipment, plant distribution system, startup equipment, planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities;

(iii) The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree.

(iv) In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

(v) A list of all needed federal, state, and local approvals related to the facility and site, identified by title and the nature of the needed approval; a copy of such approvals or a report of their status; and a copy of any application related to eligible facility and/or exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (PUHCA), as amended by the Energy Policy Act of 1992, including attachments and subsequent amendments, if any; and

(vi) A general description of the transmission facilities to which the facility will interconnect, and a color map showing their general location. If additional facilities are needed, a statement regarding whether the applicant would need to acquire rights-of-way for new facilities.

(3) Exhibit 3 shall provide a description of the need for the facility in the state and/or region, with supporting documentation.

(4) The application shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant.

(5) The application shall be accompanied by pre-filed direct testimony incorporating and supporting the application.

(6) The Chief Clerk will deliver a copy of the application to the Clearinghouse Coordinator in the Department of Administration for distribution to State agencies having an interest in the proposed generating facility.

(7) Contemporaneous with the filing of the application with the Commission, all applicants proposing a generating facility that will use natural gas must provide written notice of the filing to the natural gas local distribution company or municipal gas system providing service or franchised to provide service at the location of the proposed generating facility.

(c) Confidential Information. If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

(d) Procedure upon Receipt of Application. No later than ten (10) business days after the application is filed with the Commission, the Public Staff shall, and any other party in interest may, file with the Commission and serve upon the applicant a notice regarding whether the application is complete and identifying any deficiencies. If the Commission determines that the application is not complete, the applicant will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue a procedural order setting the matter for hearing, requiring public notice, and dealing with other procedural matters.

(e) The Certificate.

(1) The certificate shall specify the name and address of the certificate holder; the type, capacity, and location of the facility; and the conditions, if any, upon which the certificate is granted.

(2) The certificate shall be subject to revocation if (a) any of the federal, state, or local licenses or permits required for construction and operation of the generating facility not obtained or, having been obtained, are revoked pursuant to a final, non-appealable order; (b) required reports or fees are not filed with or paid to the Commission; and/or (c) the Commission concludes that the certificate holder filed with the Commission information of a material nature that was inaccurate and/or misleading at the time it was filed; provided that, prior to revocation pursuant to any of the foregoing provisions, the certificate holder shall be given thirty (30) days' written notice and opportunity to cure.

(3) The certificate must be renewed if the applicant does not begin construction within three years after the date of the Commission order granting the certificate.

(4) A certificate holder must notify the Commission in writing of any plans to sell, transfer, or assign the certificate and the generating facility.

(f) Reporting. All applicants must submit annual progress reports and any revisions in cost estimates, as required by G.S. 62-110.1(f) until construction is completed.

R8-64 APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY BY QUALIFYING COGENERATOR OR SMALL POWER PRODUCER; PROGRESS REPORTS.

(a) Scope of Rule.

(1) This rule applies to applications for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) filed by any person seeking the benefits of 16 U.S.C. 824a-3 or G.S. 62-156 as a qualifying cogenerator or a qualifying small power producer as defined in 16 U.S.C. 796(17) and (18) or as a small power producer as defined in G.S. 62-3(27a), except persons exempt from certification by the provisions of G.S. 62-110.1(g).

(2) For purposes of this rule, the term "person" shall include a municipality as defined in Rules R7-2(c) and R10-2(c), including a county of the State.

(3) The construction of a facility for the generation of electricity shall include not only the building of a new building, structure or generator, but also the renovation or reworking of an existing building, structure or generator in order to enable it to operate as a generating facility.

(4) This rule shall apply to any person within its scope who begins construction of an electric generating facility without first obtaining a certificate of public convenience and necessity. In such circumstances, the application shall include an explanation for the applicant's beginning of construction before the obtaining of the certificate.

(b) The Application. The application shall be comprised of the following five exhibits:

(1) Exhibit 1 shall contain:

(i) The full and correct name, business address, business telephone number, and electronic mailing address of the facility owner;

(ii) A statement of whether the facility owner is an individual, a partnership, or a corporation and, if a partnership, the name and business address of each general partner and, if a corporation, the state and date of incorporation and the name, business address, business telephone number, and electronic mailing address of an individual duly authorized to act as corporate agent for the purpose of the application and, if a foreign corporation, whether domesticated in North Carolina; and

(iii) The full and correct name of the site owner and, if the owner is other than the applicant, the applicant's interest in the site.

(2) Exhibit 2 shall contain:

(i) A color map or aerial photo showing the location of the generating facility site in relation to local highways, streets, rivers, streams, and other generally known local landmarks, with the proposed location of major equipment indicated on the map or photo, including: the generator, fuel handling equipment, plant distribution system, ~~and~~ startup equipment, the site boundary, planned and existing pipelines, planned and existing roads, planned and existing water supplies, and planned and existing electric facilities. A U.S.

Geological Survey map or an aerial photo map prepared via the State's geographic information system is preferred; and

(ii) The E911 street address, county in which the proposed facility would be located, and GPS coordinates of the approximate center of the proposed facility site to the nearest second or one thousandth of a degree.

(3) Exhibit 3 shall contain:

(i) The nature of the generating facility, including the type and source of its power or fuel;

(ii) A description of the buildings, structures and equipment comprising the generating facility and the manner of its operation;

(iii) The gross and net projected maximum dependable capacity of the facility as well as the facility's nameplate capacity, expressed as megawatts (alternating current);

(iv) The projected date on which the facility will come on line; and

(v) The applicant's general plan for sale of the electricity to be generated, including the utility to which the applicant plans to sell the electricity;

(vi) Any provisions for wheeling of the electricity;

(vii) Arrangements for firm, non-firm or emergency generation;

(viii) The service life of the project;

(ix) The projected annual sales in kilowatt-hours; and

(x) Whether the applicant intends to produce renewable energy certificates that are eligible for compliance with the State's renewable energy and energy efficiency portfolio standard.

(4) Exhibit 4 shall contain:

(i) A complete list of all federal and state licenses, permits and exemptions required for construction and operation of the generating facility and a statement of whether each has been obtained or applied for.

(ii) A copy of those that have been obtained should be filed with the application; a copy of those that have not been obtained at the time of the application should be filed with the Commission as soon as they are obtained.

(5) Exhibit 5 shall contain the expected cost of the proposed facility.

(6) An applicant who desires to enter into a contract for 5 years or more for the sale of electricity, whose facility will have a nameplate capacity of 5 megawatts alternating current or more, and whose facility is not a solar photovoltaic facility, shall include the three additional exhibits—as described in R8-64(b)(6)(i), (ii), and (iii) below, except an applicant who desires to enter into a contract of 5 years or more for the sale of electricity

from a solar photovoltaic facility of 25 megawatts alternating current or more shall also include the three additional exhibits referenced herein.

(i) Exhibit 6 shall contain:

a A statement detailing the experience and expertise of the persons who will develop, design, construct and operate the project to the extent such persons are known at the time of the application;

b Information specifically identifying the extent to which any regulated utility will be involved in the actual operation of the project; and

c A statement obtained by the applicant from the electric utility to which the applicant plans to sell the electricity to be generated setting forth an assessment of the impact of such purchased power on the utility's capacity, reserves, generation mix, capacity expansion plan, and avoided costs.

(ii) Exhibit 7 shall contain:

a The most current available balance sheet of the applicant;

b The most current available income statement of the applicant;

c An economic feasibility study of the project; and

d A statement of the actual financing arrangements entered into in connection with the project to the extent known at the time of the application.

(iii) Exhibit 8 shall contain:

a A detailed explanation of the anticipated kilowatt and kilowatt-hour outputs, on-peak and off-peak, for each month of the year. The explanation shall include a statement of the specific on-peak and off-peak hours underlying the applicant's quantification of anticipated kilowatt and kilowatt-hour outputs;

b A detailed explanation of all energy inputs and outputs, of whatever form, for the project, including the amount of energy and the form of energy to be sold to each purchaser; and c A detailed explanation of arrangements for fuel supply, including the length of time covered by the arrangements, to the extent known at the time of the application.

(7) All applications shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant for the purpose of the application.

(8) Applications filed on behalf of a corporation are not subject to the provision of R1-5(d) that requires corporate pleadings to be filed by a member of the Bar of the State of North Carolina. Should a public hearing be required, the requirements of G.S. 84-4 and G.S. 84-4.1 shall be applicable.

(9) Falsification of or failure to disclose any required information in the application may be grounds for denying or revoking any certificate.

(10) The application and 12 copies shall be filed with the Chief Clerk of the Utilities Commission.

(11) If an applicant considers certain of the required information to be confidential and entitled to protection from public disclosure, it may designate said information as confidential and file it under seal. Documents marked as confidential will be treated pursuant to applicable Commission rules, procedures, and orders dealing with filings made under seal and with nondisclosure agreements.

(c) Procedure upon receipt of Application. — Upon the filing of an application appearing to meet the requirements set forth above, the Commission will process it as follows:

(1) The Commission will issue an order requiring the applicant to publish notice of the application once a week for four successive weeks in a ~~daily~~ newspaper of general circulation in the county where the generating facility is proposed to be constructed and requiring the applicant to mail a copy of the application and the notice, no later than the first date that such notice is published, to the electric utility to which the applicant plans to sell the electricity to be generated. Each electric utility shall provide on its website a mailing address to which the application and notice should be mailed. The applicant shall be responsible for filing with the Commission an affidavit of publication and a signed and verified certificate of service to the effect that the application and notice have been mailed to the electric utility to which the applicant plans to sell the electricity to be generated.

(2) The Chief Clerk will deliver 2 copies of the application and the notice to the Clearinghouse Coordinator of the Office of Policy and Planning of the Department of Administration for distribution by the Coordinator to State agencies having an interest in the application.

(3) If a complaint is received within 10 days after the last date of the publication of the notice, the Commission will schedule a public hearing to determine whether a certificate should be awarded and will give reasonable notice of the time and place of the hearing to the applicant and to each complaining party and will require the applicant to publish notice of the hearing in the newspaper in which the notice of

the application was published. If no complaint is received within the time specified, the Commission may, upon its own initiative, order and schedule a hearing to determine whether a certificate should be awarded and, if the Commission orders a hearing upon its own initiative, it will require notice of the hearing to be published by the applicant in the newspaper in which the notice of the application was published.

(4) If no complaint is received within the time specified and the Commission does not order a hearing upon its own initiative, the Commission will enter an order awarding the certificate.

(d) The Certificate.

(1) The certificate shall be subject to revocation if any of the other federal or state licenses, permits or exemptions required for construction and

APPENDIX B
PAGE 12 of 12

operation of the generating facility is not obtained and that fact is brought to the attention of the Commission and the Commission finds that as a result the public convenience and necessity no longer requires, or will require, construction of the facility.

(2) The certificate must be renewed by re-compliance with the requirements set forth in this Rule if the applicant does not begin construction within 5 years after issuance of the certificate.

(3) Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or assign the certificate or the generating facility or of any significant changes in the information set forth in subsection (b)(1) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes.

(e) Reporting. — All applicants must submit annual progress reports until construction is completed.

DOCKET NO. E-100, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2013 Integrated Resource Plan Annual	)	ORDER APPROVING INTEGRATED
Update Reports and Related 2013 REPS	)	RESOURCE PLAN ANNUAL
Compliance Plans	)	UPDATE REPORTS AND REPS
	)	COMPLIANCE PLANS

HEARD: Monday, April 28, 2014, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

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

Brett Breitschwerdt, McGuireWoods LLP, 2600 Two Hanover Square, Raleigh, North Carolina 27601

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

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, P.O. Box 1551, Raleigh, North Carolina 27602

For North Carolina Waste Awareness & Reduction Network:

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

For Sierra Club and Southern Environmental Law Center:

Gudrun Thompson, Senior Attorney, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

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

Margaret Force, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

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

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

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

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

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

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

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

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

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources (collectively, the utilities),[1] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

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

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

2013 ANNUAL UPDATE REPORTS

This Order addresses the 2013 annual update reports (2013 IRPs) filed in Docket No. E-100, Sub 137, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the lOUs.

The following parties have been allowed to intervene in this docket: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Invenergy Wind Development, LLC and Invenergy Solar Development, LLC (Invenergy); Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Nucor Steel-Hertford; Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to G.S. 62-20.

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

PROCEDURAL HISTORY

On August 22, 2014, DEP and DEC moved for an extension of time to file their 2013 IRPs to October 1, 2013. The Commission granted this motion by Order dated August 28, 2013. On September 23, 2013, DEP and DEC filed a motion for a further extension until October 15, 2013. This motion was granted by the Commission on September 24, 2013.

On August 30, 2013, DNCP filed its 2013 annual update IRP and REPS compliance plan. On October 15, 2013, DEC and DEP filed their 2013 annual update IRP's and REPS compliance plans.

On October 11, 2013, the Commission issued an Order establishing February 4, 2014, as the date by which interested parties may file petitions to intervene in this docket, and the Public Staff and other intervenors may file initial comments on the utilities' IRPs and REPS compliance plans. Further, the Order set February 18, 2014, as the date by which all parties may file reply comments.

On January 6, 2014, the Commission issued an Order scheduling a public hearing to be held on March 3, 2014, for the purpose of taking non-expert public witness testimony with respect to the filed annual updated IRPs and REPS compliance plans. Due to inclement weather on March 3, 2014, the Commission canceled the public hearing.

On January 16, 2014, the Public Staff filed a Motion requesting that the Commission extend the date for petitions to intervene and initial comments to Friday, March 14, 2014, and the date for reply comments to Friday, March 28, 2014. This Motion was granted by an Order dated January 16, 2014.

On March 6, 2014, the Commission issued an Order rescheduling the public hearing for April 28, 2014.

On March 7, 2014, DEC and DEP filed a corrected inputs supplement to their 2013 IRPs.

On March 10, 2014, NC WARN filed a Motion requesting that the Commission review costs of the DEC proposed Lee Combined Cycle Plant in South Carolina. On March 11, 2014, DEC filed a Response to the NC WARN Motion. On March 21, 2014, the Commission issued an Order denying that motion.

On March 12, 2014, SACE and the Sierra Club filed a Motion requesting that the dates for comments and reply comments be extended to April 11, 2014, and April 25, 2014, respectively. This request was granted by an Order dated March 13, 2014.

On April 11, 2014, comments on the electric utilities IRPs were filed by the Sierra Club and SACE jointly, NCSEA, MAREC, the Public Staff and NC WARN. NC WARN in its comments also requested that the Commission hold an evidentiary hearing regarding DEC's growth forecasts.

On April 15, 2014, DEP, DEC and DNCP filed a Joint Motion requesting that the date for reply comments be extended to May 23, 2014. On April 17, 2014, the Commission issued an Order extending the time for the utilities to file reply comments until May 23, 2014.

On May 16, 2014, NCSEA submitted corrected comments to correct an analytical error in its comments filed on April 11, 2014. NCSEA stated that the corrected comments do not in any way alter or change its arguments or recommendations made in its original comments.

On May 22, 2014, Sierra Club and SACE submitted joint reply comments. On May 23, 2014, DNCP filed reply comments and DEC and DEP filed joint reply comments.

On June 10, 2014, NC WARN submitted a Motion to File Additional Comment containing additional and clarifying comments in response to the reply comments filed jointly by DEC and DEP.

On June 18, 2014, DEC and DEP filed a response to NC WARN's additional reply comments.

Public Hearing

Pursuant to G.S. 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, April 28, 2014, at 7:00 p.m., where 11 public witnesses spoke. The witnesses discussed the negative environmental impacts of coal plants and other fossil fuel generation versus the positive benefits of using renewable types of generation, especially solar and wind. Reducing carbon emissions, the removal of toxic coal ash from pond sites, energy efficiency, energy conservation, and demand-side management were issues brought up by the witnesses.

Request for Evidentiary Hearing on Projected Load Growth

In its April 11, 2014 comments, NC WARN stated that both DEC and DEP (collectively, Duke or Duke Energy) base their 15-year IRPs on growth in the use of electricity increasing 1.4 – 1.5% each year, even though actual growth in electricity demand has been flat for more than a decade. Further, NC WARN stated that each of the projections include the impacts of the utility's energy efficiency programs, so the actual growth Duke Energy maintains in the IRPs is even higher -- almost 1.9%. According to NC WARN, the forecasts are based on a full economic recovery and a booming growth in population, and the utilities plan to meet new growth for electricity with continued use of polluting fossil fuel plants and extremely costly nuclear plants.

NC WARN asserted that what are troublesome are the surprising inconsistencies in the forecasted growth in demand and sales stated in the IRPs and what Duke Energy officials told shareholders and the business press just weeks after the IRPs were filed. For example, NC WARN stated that in her earnings conference call with Duke Energy shareholders on November 6, 2013, Lynn Good, Duke Energy's CEO, stated that the utility actually expects growth to be in the 0.5 to 1.0% range for the foreseeable future. According to NC WARN, this information was summarized in an article by Bruce Henderson in the Charlotte Observer. The article stated that "long-term, CEO Lynn Good told financial analysts, Duke expects sales to grow only 0.5 percent to 1 percent a year. In recent years, annual growth has been about 1 percent."

NC WARN further stated that in a presentation to the Legislative Study Committee at the General Assembly on January 7, 2014, Paul Newton, Duke Energy's President for North Carolina, testified that the growth rate would be between 0.5 and 0.9%.

In addition, NC WARN stated that in an interview with Industrial Info Resources on December 16, 2013, Jim Rogers, former chairman and CEO of Duke Energy, stated that he expects electric growth to be flat for the foreseeable future. According to NC WARN, he is quoted as stating "over the next couple of decades, we're not going to be building central station generation, particularly when you factor in the effect of state renewable portfolio standards, more efficient appliances, more efficient building and new technologies that will help customers reduce electric usage." The article then summarizes his position as follows: "going forward, he said state renewable portfolio standard (RPS) policies would absorb most of what growth there will be in customer demand for electricity." NC WARN stated that Rogers subsequently repeated his forecast in other forums.

NC WARN stated that it is unable to determine which of these annual growth forecasts Duke actually believes to be accurate. According to NC WARN, one rationale given by Duke Energy officials to business reporters for the considerably lower forecasts is that they are for the Duke Energy system in its entirety. However, NC WARN maintained that this falls flat after reviewing the IRPs (or similar documents) in each of the other states that Duke Energy serves. According to NC WARN, the weighted average is a forecasted 1.33% growth rate, with only Indiana projected as significantly lower than other states. NC WARN stated that the other rationale given for the lower growth forecasts is they do not include growth in sales to wholesale customers. NC WARN submitted that this also falls flat in that there are not many potential wholesale customers in the North Carolina service area left, and their growth will not be any higher than the rest of the system.

NC WARN argued that of these differing forecasts Rogers's forecast of zero growth is in line with the most recent growth projections by the U.S. Energy Information Administration (EIA) as well as actual growth for the past decade. During 2013, EIA estimates the average U.S. residential customer used 10,870 kilowatt hours (kWh) of electricity, which is 2.2% lower than the average level of consumption between 2008 and 2012. In part due to improvements in appliance and lighting efficiency, "the overall growth trend has been slowing in recent years."

NC WARN noted that another recognized source for energy forecasts, the American Council for an Energy-Efficient Economy (ACEEE) also projects a zero or potential negative growth future for utilities. According to NC WARN, the ACEEE report states that electricity sales fell by 1.9% in 2012 over 2007's figures, and sales in the first ten months of 2013 have fallen even lower. NC WARN, submitted that the economic recession explains the decline in sales in 2008 and 2009, but it is much less clear why sales have continued to fall. Further, NC WARN stated that the ACEEE suggests that energy-efficient buildings, lighting and appliances have successfully reduced consumption, as well as energy efficiency programs and policies, warmer weather, changes in gross domestic product, changes in electricity prices, and long-term trends in energy efficiency.

NC WARN asserted that the differences between the IRP, EIA and ACEEE projections are significant in scope and the real world impacts are substantial. Together for both DEC and DEP, Duke Energy forecasts a need for 7,029 megawatts (MW) of new capacity and 34,691 MWh of additional energy sales. A forecast in the 1% to 0.5% range reduces the need for new generating plants down to a range of 2,267 MW to 4,686 MW (with similar reductions in energy). NC WARN stated that the zero growth scenario forecast propounded by Rogers, and supported by the EIA and the ACEEE, eliminates the need for additional capacity and energy entirely. NC WARN further contended that this forecast eliminates the need for the Lee Nuclear Station and all other proposed new Duke generating plants, and allows the utility to shut down all coal plants and reduce use of natural gas with a stronger commitment to energy efficiency, renewable energy resources, cogeneration and other distributed generation. Thus, NC WARN argued that the debate could and should be about how fast we can shut down coal plants and which natural gas plants should be closed.

NC WARN concluded that in light of the diverse and contradictory forecasts between those provided in the IRPs and those propounded by Duke Energy executives to shareholders, legislative commissions and the business press, an evidentiary hearing is required, and that the ramifications of following the Duke Energy IRP forecast, in rate impacts and costs to ratepayers caused by new plant construction and continuing use of coal and its associated risks, are highly significant.

In their joint May 22, 2014 reply comments, Sierra Club and SACE noted that NC WARN addressed the conflict between the load forecasts in the IRPs and remarks by Duke Energy representatives, as well as national efficiency experts. They point out that NC WARN then proposes an alternative energy future that eliminates all coal plants and new conventional generation, replacing it with energy efficiency, solar power and other forms of distributed generation and that this approach can provide an estimated annual savings for customers of more than $2 billion.

The Sierra Club and SACE state that they have not had an opportunity to review in detail the assumptions and methodology underlying NC WARN’s comments; however, they agree with general points made by NC WARN that the DEC and DEP load forecasts are overstated, and that the IRPs should include higher levels of renewable energy and energy efficiency, which are consistent with the points made in their initial comments. They state that if the Commission allows NC WARN’s motion, SACE and the Sierra Club respectfully submit the issues raised in their initial comments for the Commission’s consideration as possible additional issues for an evidentiary hearing.

Regarding NC WARN's request for an evidentiary hearing, DNCP noted that NC WARN does not focus any of its comments on DNCP's 2013 IRP. DNCP stated that NC WARN's request for an evidentiary hearing focused solely on whether the IRPs submitted by DEC and DEP are in the best interest of North Carolina ratepayers. While DNCP recognizes the Commission's discretion under Commission Rule R8-60 to hold an evidentiary hearing on the utilities' IRPs, DNCP does not view NC WARN's generic request for an evidentiary hearing as presenting compelling issues or reasoning to hold such a hearing, and, to the extent the Commission determines otherwise, DNCP believes that the hearing itself, similar to NC WARN's comments, should be limited to DEC's and DEP's plans.

In the joint May 23, 2014 reply comments of DEC and DEP, Duke asserted that NC WARN rehashes its previous IRP contentions and yet again makes the completely false assertion that DEC and DEP's IRP updates are based upon exaggerated load forecasts. Duke opined that NC WARN advances unsupported hyperbole that the resource plans filed by DEC and DEP would "bankrupt North Carolina's economy," simply because Duke relies upon a mix of resources that include reliable and cost-effective baseload nuclear, gas and coal generation. Without apparent regard to cost, reliability or feasibility, NC WARN instead proposes that its allegedly superior alternate energy future can be achieved by "eliminating all coal plants and all new generation." Duke argues that as in past IRP dockets the Commission should dismiss NC WARN's meritless contentions.

According to Duke, NC WARN's criticism of "differing" load forecasts is entirely misplaced. NC WARN alleges that the load forecasts contained in the 2013 DEC and DEP IRP updates are higher than various general load growth comments attributed to Duke Energy CEO Lynn Good, Duke Energy State President-North Carolina Paul Newton, and former Duke Energy Corporation CEO Jim Rogers in various public or media comments from November 2013, January 2014, and December 2013, respectively. Duke argued that NC WARN insinuated that Duke Energy filed one set of load forecasts with the Commission, yet told other audiences that the true load forecast is much lower. According to Duke, it is disturbing that NC WARN apparently fails to understand that Duke Energy operates utilities in six states, and that the referenced Duke Energy executives were not speaking about the DEC and DEP 2013 load forecasts in their comments. Duke noted that the load forecasts for DEC and DEP in North Carolina and South Carolina are different than the outlook for the Duke Energy utilities in Indiana, Ohio, Kentucky or Florida; are different than the outlook for the aggregated Duke Energy utilities (referred to by Duke Energy as Franchised Electric & Gas); and are different than the reported outlook for the United States electric industry in general - - which were the subject of the various comments by the Duke Energy executives. According to Duke, the comparison among different utilities or data from national organizations such as EIA is complicated due to different terminology, different forecast horizons or different load definitions, and NC WARN's comments at best fail to attempt a true "apples-to-apples" comparison. Duke stated that the facts are that DEC's and DEP's loads are projected to grow at a faster pace than the Duke Energy U.S. Franchised Electric & Gas load or the U.S. (USFE&G) electric industry load, due to the higher population growth rate and growing wholesale load contribution in North Carolina and South Carolina. Duke maintained that former CEO Rogers often spoke in terms of the U.S. electric industry as a whole and often discussed negative load growth in terms of national use-per-customer trends, not total sales and certainly not as to DEC and DEP load forecasts. DEC and DEP's projected growth in number of customers (driven by population growth or migration of population from other parts of the country) more than offsets any decline in per-customer usage growth. In order for DEC or DEP to have "zero growth" as NC WARN asserts, average electric use per customer would have to decline by negative one percent (- 1.0%) or more each and every year over the planning horizon to 2028.

Duke pointed out that NC WARN did not prepare a true load forecast, but simply assumed "zero growth." Duke stated that such an assumption is entirely inconsistent with the actual data utilized to prepare the load forecasts for the Duke's 2013 IRP updates. Duke stands by the reasonableness of the load forecasts contained in its 2013 IRP updates, which have been reviewed by and are supported by the Public Staff.

According to Duke, NC WARN's "Model" and Zero Growth Scenario are unrealistic. In its comments, NC WARN touted its own proposed resource plan as superior to those contained in DEC and DEP's 2013 IRP updates and stated that its "analysis shows that a zero growth scenario allows for phase out of all coal plants, eliminates the need to construct new nuclear plants and reduces the need for some existing natural gas." Duke asserted, however, that when information is sought about the support for NC WARN's allegations, no substantive analysis is forthcoming. Duke stated that in response to a data request seeking a copy of NC WARN's "plan" and "model," and the specific inputs used in the production cost simulation models and screening models supporting the NC WARN comments, NC WARN responded,

> NC WARN's "plan" (used interchangeably with "model") is described in the comments, paragraphs 25-29, and is based on the charts in Appendix A and the NC WARN's report filed in last year's initial Comments on the IRPs....NC WARN has not prepared production cost simulation models and screening models of the NC WARN plan or model, nor developed any of the inputs listed in the request, except recently looked at natural gas price forecasts as part of the preparation of the [NC WARN avoided cost testimony filed in E-100, Sub 140].[1]

On June 10, 2014, NC WARN filed a Motion for Leave to File Additional Comment. In support of its motion, NC WARN asserted that in its reply comments filed May 23, 2014, Duke aggressively replied to NC WARN’s comments by stating

> NC WARN insinuates that Duke Energy filed one set of load forecasts with this Commission, yet told other audiences that the true load forecast is much lower. It is disturbing that NC WARN apparently fails to understand (or wilfully ignores) that Duke Energy operates utilities in six (6) states, *and that the referenced Duke Energy executives were not speaking about the DEC and DEP 2013 load forecasts in their comments.* (emphasis in original)

NC WARN stated that this ignores NC WARN’s paragraph 8, footnote 8 in its comments, which clearly contradicts Duke Energy’s comment that the much lower forecasts by Duke Energy officials do not conflict with the IRPs filed in this docket, as they were addressing the entire Duke Energy system, and not just North Carolina. Footnote 8 reads:

> One rationale given by Duke Energy officials and floated to business reporters for the considerably lower forecasts is that they are for the Duke Energy system in its entirety. This falls flat after reviewing the IRPs (or similar documents) in each of the other states Duke Energy serves – the weighted average is a forecasted 1.33% growth rate, with only Indiana

[1] NC WARN Response to Duke Energy Data Request 10, May 1, 2014.

> projected as significantly lower than other states. The other rationale given for the lower growth forecasts is they do not include growth in sales to wholesale customers. This also falls flat in that there just are not many potential wholesale customers in the North Carolina service area left, and their growth will not be any higher than the rest of the system.

NC WARN noted that the worksheet showing the weighted average of growth rates in the various states Duke Energy serves was attached to its comments, and that the growth rates reported in the most recent IRPs (or equivalent planning documents) were reviewed in each of the states from utility commission websites. NC WARN stated that the number of customers came directly from the Duke Energy website to provide a weighted average of a forecast of 1.33% for the entire Duke Energy service areas. NC WARN noted that a fundamental assumption was that the mix of customer classes was approximately similar in each of the states as classification of customer classes varied.

NC WARN contended that the weighted average of 1.33% was still considerably higher than the 0.5 to 1.0% range given by CEO Good in her earnings conference call with Duke Energy shareholders on November 6, 2013, and the 0.5 and 0.9% given by Duke President Newton in January 2014 to a legislative committee in which he discussed Duke Energy in North Carolina. Given the disparity between the comments by the Duke Energy officials, some of which were under oath to regulatory commissions, NC WARN stood by its comments that the Commission should investigate why differing forecasts were used in different forums, and what forecast Duke Energy is actually using for planning purposes.

NC WARN submitted that whether these discrepancies were intentional or inadvertent the difference between a forecast in the 1.33 to 1.5% range and the considerably lower forecasts by Good and Newton, and especially that of Rogers, results in billions of dollars of new plant construction.

On June 18, 2014, Duke filed additional reply comments in response to those of NC WARN. Duke stated that in its May 23, 2014 Joint Reply Comments Duke completely refuted NC WARN's assertions that Duke has made conflicting load growth projections. Duke further stated that it does not agree with NC WARN's aggregate load forecast for all of Duke's USFE&G. However, assuming that NC WARN's calculations are correct, Duke noted that its USFE&G forecast is irrelevant to the examination of North Carolina's future electric needs that the Commission is conducting in this docket. Further, Duke submitted as attachments the transcript of the November 6, 2013 earnings call and a slide used in the presentation. Duke pointed out that the transcript and slide confirm that CEO Good and others were discussing Duke's USFE&G, rather than forecasts specific to North Carolina. Duke also attached page 7 of the presentation made by Duke President Newton in January 2014 to a legislative committee. Duke explained that this page shows that Newton was referring to the growth of electricity usage in the United States from 1950 to 2040. In addition, Duke cited its confidential Table C-1 in its IRPs showing wholesale customer load growth, including a new contract with an existing wholesale customer that adds more than

800 MW of additional load by 2022.[1] In conclusion, Duke stated that Duke has not submitted or used differing load forecasts and it stands by the accuracy of the forecasts included in its IRPs.

Discussion

As previously noted, G.S. 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." Thus, the Commission's analysis in this docket with regard to future use of electricity is focused on an estimate of future use in North Carolina. Although regional and national forecasts of electricity usage are helpful in understanding trends and potential impacts on an individual state's needs, they are not a substitute for the type of North Carolina focused analyses that Duke provided in its IRPs. Further, as more fully discussed below, the Public Staff has reviewed the economic, weather-related, and demographic assumptions underlying Duke's peak and energy forecasts. The Public Staff found that Duke has employed accepted statistical and econometric forecasting practices, and it believes that Duke's conclusions are reasonable for planning purposes.

In addition, one of NC WARN's contentions is that the 750-MW Lee combined cycle plant to be built by Duke in South Carolina (Lee CC Plant) is not needed. As previously stated, on March 10, 2014, NC WARN filed a Motion to Review Costs of Proposed Plant in South Carolina in this docket. By its motion, NC WARN requested that the Commission conduct a review of the costs and need for the Lee CC Plant. On March 21, 2014, after reviewing Duke's response to the motion and the applicable statutes, the Commission issued an order concluding that there was no basis for the Commission to make a determination at this time of the need for or estimated cost of the Lee CC Plant.

On April 28, 2014, the Commission held a public hearing in Raleigh for the purpose of receiving testimony from ratepayers. Several witnesses attended the hearing and provided the Commission with their views and concerns regarding least cost and environmentally sound electric generating resources. In addition, the Commission has received numerous consumer statements of position from ratepayers on these and other subjects. The evidence from the public hearing, the IRPs, the consumer statements of position and the parties' comments and reply comments provide the Commission with an extensive record in this docket. Having reviewed the record and considered the parties' arguments, the Commission concludes that the substantive issues raised by ratepayers at the hearing and in their statements of position, as well as those raised by NC WARN in its comments, motion for an evidentiary hearing and additional reply comments, have been adequately addressed by Duke in its comments, reply comments and additional reply comments. As a result, the Commission concludes that the record in this proceeding includes sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing.

The Commission fully supports the use of an evidentiary hearing in situations where it is warranted. However, no reasonable basis for convening an evidentiary hearing has been

[1] Duke noted that NC WARN did not request to sign a confidentiality agreement and, therefore, did not have this information.

demonstrated in this case. Therefore, the Commission is not persuaded that there is good cause to grant NC WARN's motion that the Commission hold an evidentiary hearing in this docket. As a result, the motion should be denied.

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

FINDINGS OF FACT

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

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

3. The IOUs included a full discussion of REPS compliance and their plans should be approved.

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

5. DEP and DEC in future IRPs should provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

6. DEP, DEC and DNCP have adequately addressed the issues raised by the intervenors.

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

PEAK AND ENERGY FORECASTS

The Public Staff has reviewed the 15-year peak and energy forecasts (2014–2028) of DEP, DEC, and DNCP. The compound annual growth rates (CAGR) for the forecasts are within the range of 1.2% to 1.4%.

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

In assessing the reasonableness of the forecasts, the Public Staff first compared the most recent weather-normalized peak loads to the utilities' forecasts in the 2012 IRPs. Second, the Public Staff analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2008 IRPs in comparison to their actual peak demands and energy sales. A review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, the Public Staff reviewed several of the assumptions that underlie the forecasts of other adjoining utilities and the SERC Reliability Corporation (SERC).

DEP

DEP's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.2%, as compared to a 0.9% growth rate in the 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEP expects its summer peaks to grow at a rate of 1.7%. The increase in the growth rate in peaks is partially due to DEP's adoption of DEC's methods of forecasting load and calculating reserve margins, which considers DSM as a resource rather than as a decrement to the load forecast. In prior IRPs, DEP deducted the DSM load reductions from its forecasted peak loads. The average annual growth of its summer peak, which is considered its system peak, is forecasted to be 171 MW for the next 15 years, in comparison to the 130 MW forecast in last year's IRP. DEP predicts that in 15 years, the load reductions from its DSM programs will reduce its peak load by approximately 4%, as compared to a 9% reduction forecast in the 2012 IRP.

DEP's energy sales, including the impacts from its EE programs, are predicted to grow at a CAGR of 1.4% as compared to 1.0% in the 2012 IRP. DEP predicts that in 15 years, the MWh reductions from its EE programs will reduce its energy sales by approximately 4%, which is similar to its projection in its 2012 IRP.

The Public Staff's review of DEP's weather adjusted peak load forecasting accuracy for one year shows that the predictions in the 2012 IRP had a forecast error of 2%, caused in part by the relatively mild summer temperatures in 2013.[1] The Public Staff's review of DEP's actual peak load over five years (2009-2013), as compared to its forecasts, shows a forecast error of 3%. This 3% forecast error results in an average annual overestimation of 407 MW. A comparison of DEP's actual energy sales over the same five years with those predicted in its 2008 IRP reflects a 5% forecast error.

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

DEC

DEC's 15-year forecast predicts that its adjusted summer peaks will grow at a CAGR of 1.4%, as compared to the 1.7% growth rate projected in the 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DEC expects its summer

[1] The Mean Absolute Error is used to calculate the forecast error. The one-year review incorporates weather normalized peak demands while the five-year review incorporates actual unadjusted peak demands.

peaks to grow at 1.9%. The average annual growth of its summer peak, which is considered its system peak, is forecasted to be 283 MW for the next 15 years, in comparison to the 321 MW forecast in last year's IRP. DEC predicts that load reductions from the activation of its DSM programs will reduce its peak load by approximately 6% in 2028.

DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 1.4%. This growth rate in energy sales is less than the 1.7% predicted in the 2012 IRP. DEC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 7% in 2028.

The Public Staff's review of DEC's weather adjusted peak load forecasting accuracy for one year shows that its 2012 IRP forecast had a 1% forecast error. However, a review of DEC's actual peak loads for five years (2009-2013), as compared to its forecasts, indicates a forecast error of 11%. This 11% forecast error indicates an average annual overestimation of 1,884 MW of capacity, 1,680 MW of capacity when adjusted for weather. In regard to DEC's energy sales forecasts, a comparison of its actual energy sales over the same five years with those predicted in 2008 prediction indicates an 8% forecast error.

The Public Staff's review indicates that DEC's forecasts for both peak demand and energy sales have been consistently higher than actual loads and sales since 2008.

The Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's 2013 peak and energy forecasts are reasonable, and that DEC has employed accepted statistical and econometric forecasting practices. However, the Public Staff is concerned with DEC's pattern of over-forecasting more often than under-forecasting its load. DEP's IRP indicates that DEP has adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and its peak demands has generally been more accurate than DEC's forecasting. For its energy sales forecasts, DEP has typically relied on the monthly-based econometric model with end-use data over a span of ten or more years of historical data. This model has been used for over 30 years, and during these years, DEP has relied on the load factor method to forecast its peak demands. While DEC has also used econometric models, it has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years. In response to inquiries from the Public Staff, DEC indicated that it is currently preparing to incorporate statistically adjusted end-use data in its models to improve the accuracy of its forecasts in future IRPs. While the Public Staff believes that DEC's 2013 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC carefully review and incorporate the best forecasting practices of DEP and DEC.

<u>DNCP</u>

DNCP's 15-year forecast predicts that its adjusted[1] summer peaks will grow at a CAGR of 1.2%, a decrease from the projected 1.5% growth rate in its 2012 IRP. Without the reduction in peak demand resulting from the implementation of its EE programs, DNCP expects its summer peaks to grow at 1.6%. The average annual growth of its summer peak is forecasted to be 239 MW

[1] Adjusted for new and existing DSM programs and load reductions associated with new EE programs as reported in Appendix 2H, p. AP-9, 2013 DNCP IRP.

for the next 15 years, in comparison to the 285 MW forecast in the 2012 IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2028 peak load by approximately 1%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.4%, which is a decrease from the projected 1.6% growth rate in the 2012 IRP. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% in 2028.

The Public Staff's review of DNCP's weather adjusted peak load forecasting accuracy for one year shows that the predictions in its 2012 IRP had a forecast error of 3%. The Public Staff's review of DNCP's actual peak loads over the last five years (2009-2013), as compared to its 2008 predictions, indicates a forecast error of 5%. This 5% forecast error results in an average annual overestimation of 787 MW. In regard to DNCP's energy sales forecasts, an annual comparison of its actual sales with its predicted sales in its 2008 IRP indicates a forecast error of 3%.

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

SUMMARY OF GROWTH RATES

The following table summarizes the growth rates for the IOUs' system peak and energy sales forecasts based on their IRP filings.

2014- 2028 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	1.2%	1.4%	1.4%	171
DEC	1.4%	1.5%	1.4%	283
DNCP	1.2%	1.1%	1.4%	239

The Commission has reviewed the 2013 IRP update reports submitted by the IOUs in this docket as well as their related reply comments to various issues raised by the Public Staff and other intervenors. The Commission finds and concludes that the 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy these loads, and reserve margins are reasonable and should be approved for purposes of updating the information contained in the biennial plans submitted in this docket.

The Public Staff in its comments went into detail describing the peak and energy forecasts submitted by DEP, DEC and DNCP. It found that the economic, weather-related, and demographic assumptions underlying DEP and DNCP's peak and energy forecasts are reasonable, and that both have employed accepted statistical and econometric forecasting practices. It concluded that DEP and DNCP's peak load and energy forecasts are reasonable for planning purposes. The Commission concurs with the Public Staff.

In regard to the forecasts submitted by DEC, the Public Staff's review indicated that DEC's forecasts for both peak demand and energy sales have been consistently higher than actual loads and sales since 2008.

As was the case with DEP and DNCP, the Public Staff believes that the economic, weather-related, and demographic assumptions underlying DEC's 2013 peak and energy forecasts are reasonable, and that DEC has employed accepted statistical and econometric forecasting practices. However, the Public Staff is concerned with DEC's pattern of over-forecasting more often than under-forecasting its load. DEP's IRP indicates that DEP has adopted DEC's forecasting methods, even though DEP's forecasting of its energy sales and its peak demands has generally been more accurate than DEC's forecasting. For its energy sales forecasts, DEP has typically relied on the monthly-based econometric model with end-use data over a span of ten or more years of historical data. This model has been used for over 30 years, and during these years, DEP has relied on the load factor method to forecast its peak demands. While DEC has also used econometric models, it has made various modifications to the general econometric equations used for its energy sales and peak demand forecasts over the last 30 years. In response to inquiries from the Public Staff, DEC indicated that it is currently preparing to incorporate statistically adjusted end-use data in its models to improve the accuracy of its forecasts in future IRPs. While the Public Staff believes that DEC's 2013 forecasts are reasonable for planning purposes, the Public Staff recommends that DEC carefully review and incorporate the best forecasting practices of DEP and DEC.

In its reply comments, DEC agreed that the DEC forecast developed in 2008 was too high; however, it was important to note that most of the forecast error was due to the severe economic downturn that occurred in 2009 and which no one reasonably foresaw. In 2009, instead of experiencing load growth, the DEC peak dropped over 500 MW due to the considerable loss of industrial load. DEC suffered more than DEP and most utilities in the 2009 recession due to its large amount of industrial load, particularly from textiles. Since 2009, the DEC weather adjusted peak has grown an average of 1.1% despite a very sluggish economic recovery. Also, the DEC peak forecast developed in 2010 projected a 2013 value that was only 131 MW different than the actual weather adjusted value for the year 2013. Thus, DEC acknowledges the anomaly in the load forecast caused by the severe economic downturn, but believes the 2013 load forecast is reasonable. However, DEC and DEP note that their forecasting methodology is always evolving in an effort to further improve the process, as a result of post-merger best practices and otherwise.

The Commission is satisfied with DEC's explanation of this issue for purposes of this update proceeding and agrees with the Public Staff that DEC's peak load and energy forecasts are reasonable for planning purposes.

SYSTEM PEAKS AND USE OF DSM RESOURCES

DEP's 2013 annual system peak was 12,166 MW, as compared to 12,770 MW in 2012. At the time of the peak, which occurred on August 12, 2013, at the hour ending 4:00 p.m., DEP activated its EnergyWise Home and Commercial, Industrial, and Government Demand Response programs, which reduced peak load by 87 MW and 15 MW, respectively. DEP activated its DSM programs on five of its ten highest summer loads in 2013 for an average load reduction of 96 MW. DEP's 2012 IRP projected that it would have 828 MW available from its DSM, EE, and voltage control programs, of which 728 MW could be activated to reduce its 2013 summer peak.

DEC's system peaked at 16,482 MW on August 16, 2013, at the hour ending 5:00 p.m. The 2012 system peak was 17,740 MW. DEC did not activate its DSM or load curtailment programs at the time of its 2013 system peak; rather, DEC activated its DSM at only two of its top ten highest summer loads for an average load reduction of 111 MW. DEC's 2012 IRP projected the availability of 872 MW from its DSM programs to reduce its summer peak.

DNCP's 2013 annual system peak of 16,366 MW occurred on July 19, 2013, at the hour ending 4:00 p.m. Its 2012 system peak was 16,787 MW. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[1] for a load reduction of 14 MW and its Air Conditioning Cycling Program for a reduction of 50 MW. DNCP activated these two DSM programs on seven of its ten highest summer loads in 2013 for an average reduction of 63 MW. DNCP's 2012 IRP projected the availability of 83 MW from its DSM programs to reduce its 2013 summer peak.

The Commission agrees with the Public Staff's conclusion that DNCP and DEP generally appear to have maximized their available DSM resources to reduce their peak demands. While the temperatures during the summer of 2013 were relatively mild and may have reduced the need for use of DSM, all three utilities should maximize these DSM resources in the future.

RESERVE MARGINS AND RESERVE MARGIN ADEQUACY

In its comments, the Public Staff noted that in 2012 DEP and DEC contracted with Astrape Consulting to conduct a detailed resource adequacy assessment that included an evaluation of their resource margins. Astrape's study provided DEP and DEC each with a recommended system reserve margin based on the Loss of Load Expectation (LOLE) probabilistic assessment. The LOLE is a metric that targets the probability of the loss of load on one day in a ten-year period, or one firm load shed event resulting in unserved energy for a firm customer on one day in a ten-year period. A greater frequency of loss load probability is generally considered to be inadequate system reliability. Based on Astrape's analyses, the reserve margins that correlate with this LOLE are 14.5% for DEP and 14% for DEC. Additional analysis is planned by Astrape to verify the adequacy of the target reserve margins now that the Joint Disptach Agreement (JDA) has been implemented.

According to the Public Staff, DNCP utilizes the PJM capacity planning process for long- and short-term planning of capacity needs. The current (2012) study recommends use of a reserve

[1] The Distributed Generation Pilot operates only in Dominion's Virginia jurisdiction.

margin of 15.6% to satisfy the reliability criteria required by the North American Electric Reliability Corporation (NERC), Reliability First Corporation, and PJM's Planned Reserve Sharing Group. DNCP utilizes a coincidence factor to account for the historically different peak periods between DNCP and PJM and therefore determine its ability to meet its PJM reserve requirements. This coincidence factor reduces DNCP's reserve margin requirement to 11.2%. DNCP also includes a 16.2% upper margin, which is commensurate with the upper bound that PJM's Reliability Pricing Model (RPM) market auction has historically cleared. The DNCP planning reserve margin remains at 11%.

For the planning period 2014 to 2028, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the planned reserves are:

Utility	Target Reserve Margin	Planned Reserve
DEP	14.5%	14.9% to 19.6%
DEC	14.5%	14.3% to 21.5%
DNCP	11%	11.2% to 17.6%

The Public Staff explained DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period and will exceed the minimum planning target of 14.5% by 3% or more in 2014-2016 due to a decrease in the load forecast. The IRP also states that the reserves exceed the minimum target by an average of approximately 3% to 5% in 2019, 2022, and 2023 as a result of the addition of large CC facilities. The Public Staff considers the planned reserves adequate.

DEC's IRP indicates that its reserve margins will meet its target reserve margin percentages for the planning period and will exceed the minimum planning target of 14.5% by an average of approximately 3% to 7% after the additions of large base load facilities in 2024 and 2026. The Public Staff concludes that DEC's planned reserves are adequate.

The Public Staff noted that differences in projected versus actual peak load growth can have a significant impact on the reserve margin. If the forecasted CAGR of DEC's peak loads grow at 1.0%, as opposed to the 1.4% rate projected in its 2013 IRP, the reserve margins will remain over 20% for most of the planning period.

The Public Staff, in its comments, expressed that DEP and DEC do not appear to be fully considering the large number of solar qualifying facilities (QFs) in the interconnection queue that could provide significant amounts of energy and capacity over the planning period, and the Public Staff has recommended that they include more realistic assumptions of potential solar energy and capacity. However, inclusion of these potential solar resources should not affect the short-term action plans.

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

Based on its review of the IRPs, the Public Staff believes the reserve margins filed by the IOUs are reasonable for planning purposes.

In their April 11, 2014 joint comments, SACE and Sierra Club stated that while the 14.5% reserve margin appears reasonable, Duke Energy's method of calculating it is not. The treatment of demand response in the DEC and DEP reserve margin calculations raises concerns that the companies may be planning for excessive reserves.

According to SACE and Sierra Club, in their reserve margin calculations DEC and DEP treat demand response as a resource with its own reserve requirement, contrary to NERC definitions and guidance. In its October 14, 2013 order on the 2012 utility IRPs, the Commission stated that DEC "should consider demand response in programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP." Both 2013 IRPs (which, to be fair, were filed just days after the Commission's order) rely on the method previously used by DEC that was recently rejected by the Commission.

Astrape conducted both the DEC and DEP reserve margin studies; however, the treatment of demand response—specifically whether it requires backstand reserves—in the studies differed. In the DEP study, demand response is treated as a load adjustment, which does not require its own reserve requirement. In the DEC study, demand response is treated as a resource option with its own reserve requirement, thereby increasing the reserve capacity.

SACE and Sierra Club stated that for purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by NERC, net internal demand includes unrestricted, non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load, and demand response. DEP's previous method of accounting for demand response by adjusting load appears to be more consistent with NERC guidance than the method still used by DEC and now adopted by DEP.

According to SACE and Sierra Club, while DEC claims that it has looked at program-specific data in making the determination as to the proper treatment of demand response programs, it has recently acknowledged that it has no actual data to offer in support of this claim. To the contrary, Duke Energy data actually indicate that both DEC and DEP demand response programs are dispatchable and controllable. In fact, DEC reports that its demand response programs have been activated a number of times, and most programs have achieved reductions consistent with (or even in excess of) expected reductions.

In summary, SACE and Sierra Club argued that with the exception of the DEC PowerManager (air conditioner) program, Duke Energy should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand. This would align DEC and DEP with the most straightforward interpretation of NERC guidance. With respect to the recent performance of its air conditioner demand response program only, its recent performance suggests that DEC should either model the program as a resource (which would require average backstand of 14.5%) or adjust the expected reduction to reflect the results of recent activations.

In their joint reply comments, DEC and DEP responded that while acknowledging that the Companies' reserve margins appear reasonable, SACE and Sierra Club contend that the Companies' reserve margins may be too high in light of treating demand response as a resource instead of an offset to load. SACE and Sierra Club erroneously believe the Company would keep the same target reserve margin with the change in methodology. This is an incorrect assumption. If DEC and DEP adopt the methodology to treat DSM as a reduction to load, the Companies will be required to raise their reserve margin to maintain the same level of reliability.

DEC and DEP explained that target reserve margins are developed to achieve a specific level of reliability, typically expressed in LOLE of one day in ten years. This LOLE level is the constant, irrespective of whether DSM is treated as a resource or as a load reduction. Below are results from DEC's most recent reserve margin study, conducted by Astrape Consulting (an energy consulting firm with a focus on resource adequacy and resource planning) in 2012. Astrape Consulting proposed a minimum target reserve margin of 14.5% if DSM (called DR for Demand Response by Astrape) is treated as a resource and 15.25% if treated as a reduction to load. The Company chose to treat DSM as a resource and used the 14.5% Reserve Margin. If the Company were to adopt the methodology to treat DSM as a load reduction as SACE and Sierra Club appear to desire, using the higher 15.25% minimum target planning reserve margin would be appropriate.

Based on its review of the IRPs, the Public Staff believes that the reserve margins filed by the IOUs are reasonable for planning purposes. SACE's and Sierra Club's joint comments stated that while DEP and DEC’s 14.5% reserve margin appears reasonable, Duke Energy’s method of calculating it is not. The treatment of demand response in the DEC and DEP reserve margin calculations raises concerns that the companies may be planning for excessive reserves. The details regarding this issue and DEP's and DEC’s response are discussed above. The Commission is satisfied that the IOUs reserve margins and calculation methods are reasonable for purposes of this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 3

REPS COMPLIANCE PLAN REVIEW

In its comments, the Public Staff reviewed and analyzed various aspects of the IOUs’ DSM and EE forecasts and programs. The following information was provided by the Public Staff in regard to REPS compliance.

General Statute 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and EE through the REPS. One MWh of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction[1] (or through DSM measures, in the case of EMCs and municipalities). Electric public utilities can use EE measures to meet up to 25% of the general requirements in G.S. 62-133.8(b). One MWh of savings from DSM, EE, or demand reduction creates one energy efficiency certificate (EEC), which is similar to a REC and is used to demonstrate compliance with the REPS. EMCs and municipalities may use DSM and EE to meet the requirements in G.S. 62-133.8(c) without any limits. They may also use energy from a hydroelectric power facility and allocations from SEPA to meet up to 30% of the general requirements. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of G.S. 62-133.8(b) and (c), with the exception of DNCP, which can use out-of-state RECs to meet 100% of the requirements. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2013 and 2014 is equal to 3% of its North Carolina retail sales for the preceding year. For 2015, this amount increases to 6%.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans (Plans). Electric power suppliers must file their Plans on or before September 1 of each year and explain how they will meet the requirements of G.S. 62-133.8(b), (c), (d), (e), and (f). The Plans must cover the current year and the next two calendar years, or in this case 2013, 2014, and 2015 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5). The instant docket includes the plans filed by DEP, DEC, and DNCP, and their wholesale customers in North Carolina for which they are contracted to provide REPS compliance services.

DEP

DEP filed its 2013 Plan along with its IRP on October 15, 2013. DEP has contracted for and banked sufficient resources to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the electric power suppliers for which it is providing REPS compliance services. DEP is contractually obligated to secure resources to meet all the REPS requirements of the City of Waynesville and the Towns of Sharpsburg, Stantonsburg, Black Creek, and Lucama (collectively, DEP's Wholesale Customers). After filing its Plan, DEP contracted to provide REPS compliance services to the Town of Winterville for 2013 and beyond.

DEP intends to use EE programs to meet 25% of its REPS requirements. Energy allocations from SEPA will be used to meet up to 30% of the general requirement of the City of Waynesville, the only DEP Wholesale Customer that receives energy from SEPA. Hydroelectric qualifying facilities will also provide RECs for DEP's other Wholesale Customers and its retail customers. DEP will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEP and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power

[1] "Electricity demand reduction," as used here, is a technical term defined in G.S. 62-133.8(a)(3a).

providers, some of which are combined heat and power facilities. DEP plans to use the increased availability of solar energy to help it meet the general requirement.

DEP will use the following methods to meet the solar set-aside: (1) its residential solar PV program, (2) in-state solar PV and thermal REC purchases, and (3) out-of-state solar REC purchases.

DEP anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEP files its measurement and verification plan for each EE program as part of its request for Commission approval of the program.

DEC

DEC filed its 2013 Plan along with its IRP on October 15, 2013. DEC has contracted for or procured sufficient resources to meet the REPS requirements of G.S. 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. DEC is contractually obligated to secure resources to meet all the REPS requirements of the following electric power suppliers: Rutherford EMC, Blue Ridge EMC, the City of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers).

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities and energy allocations from SEPA will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers. Hydroelectric qualifying facilities and the increased capacity of DEC's Bridgewater hydroelectric facility, following its modification in 2012, will provide RECs for DEC's retail customers. DEC will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to meet the general requirement. A portion of the general requirement of DEC and its Wholesale Customers will be met by executed purchased power agreements and REC-only purchases from landfill gas and biomass power providers, some of which are combined heat and power facilities. However, DEC has reduced its reliance on biomass for future REPS compliance because of the increased availability of solar energy and other renewable resources. DEC also expects to make some use of solar resources to satisfy the general requirement.

DEC will use the following methods to meet the solar set-aside: (1) self-owned distributed solar PV facilities, (2) in-state solar PV and thermal REC purchases, and (3) out-of-state solar REC purchases.

DEC anticipates that its REPS compliance costs will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DEC filed an update to its EM&V plan in its 2013 application for cost recovery of DSM and EE programs in Docket No. E-7, Sub 1032.

DNCP

DNCP's 2013 Plan was filed on August 31, 2013, as an addendum to its IRP. DNCP has contracted for and banked sufficient resources to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and the Town of Windsor (Windsor), for which it is providing REPS compliance services. DNCP plans to use EE, purchased RECs, and new self-generated renewable energy to meet the general REPS requirements of G.S. 62-133.8(b) and (c) for itself and Windsor. DNCP will rely on out-of-state RECs to meet most of its compliance requirements, as allowed by G.S. 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. DNCP intends to purchase unbundled solar RECs for itself and Windsor to meet the solar set-aside requirements during the planning period. DNCP's total costs are the same as its incremental costs because it intends to purchase RECs that are not bundled with energy to meet its REPS requirements.

DNCP anticipates that the REPS compliance costs for itself and Windsor will be well below the cost caps in G.S. 62-133.8(h)(3) and (4) for the planning period.

DNCP filed an update to its measurement and verification plan in its 2013 application for cost recovery of DSM and EE programs in Docket No. E-22, Sub 494.

REPS COMPLIANCE COMPARISON TABLES

The tables in this section are drawn from data submitted in the DEP, DEC, and DNCP Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year. For instance, the sales in the 2013 column are projected sales for calendar year 2012. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for preceding year

	Compliance Year		
Electric Power Supplier	**2013**	**2014**	**2015**
DEC	58,562,512	59,161,845	59,743,779
DEP	36,737,450	37,217,015	37,722,745
DNCP	4,161,815	4,223,188	4,080,270
TOTAL	99,461,777	100,602,048	101,546,794

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEC	DEP	DNCP
2013	Incremental Costs	8,575,016	21,026,450	557,326
	Cost Cap	63,600,083	42,520,860	3,947,064
	Percent of Cap	13%	49%	14%
2014	Incremental Costs	12,563,910	24,846,641	1,453,756
	Cost Cap	64,543,124	42,825,158	4,191,726
	Percent of Cap	19%	58%	35%
2015	Incremental Costs	15,104,036	22,550,528	1,487,743
	Cost Cap	106,425,364	68,889,101	6,660,020
	Percent of Cap	14%	33%	22%

SWINE WASTE AND POULTRY WASTE SET-ASIDES

Some electric power suppliers indicated in the Plans filed in 2011 that they had difficulty in obtaining RECs to comply with the swine and poultry waste set-asides in G.S. 62-133.8(e) and (f), which require them to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste beginning in 2012.

In May 2012, the Commission issued an order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts to meet these compliance requirements. Most electric power suppliers responded and filed a joint motion seeking to delay the swine and poultry waste set-asides as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they were having difficulty acquiring RECs to meet the swine and poultry waste set-asides because the technology for waste-to-energy facilities was still in its infancy and would need more time to reach maturity.

In November 2012, the Commission issued an order that eliminated the swine waste set-aside for 2012 and delayed the poultry waste set-aside until 2013. This order required DEP and DEC to file tri-annual reports describing the state of their compliance with the set-asides and reporting on their negotiations with the developers of swine and poultry waste-to-energy projects. The order further required them to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

On September 16, 2013, many of the electric power suppliers filed another joint motion to delay the swine and poultry waste set-asides, similar to the request they filed in 2012. In the proceedings on this motion, DEC indicated that it would not be able to comply with the poultry waste set-aside in 2013. DEP indicated that it expected to be able to comply with the poultry waste requirement in 2013, but in its Plan it states that compliance in 2014 or 2015 is unlikely. DNCP indicated that it has been able to secure enough out-of-state poultry waste RECs to meet its requirements for 2013 and 2014, but has not secured enough in-state poultry RECs for Windsor. All the utilities stated that they would be unable to comply with the swine waste set-aside in 2013.

On December 20, 2013, the Commission issued a Notice of Decision and Order in Docket No. E-100, Sub 113, which delayed the swine and poultry waste set-asides until 2014. The order extended the tri-annual reporting to DNCP and most other EMCs and municipal electric systems. It also requested that the Public Staff hold stakeholder meetings in 2014 and 2015 to facilitate compliance with the swine and poultry waste set-asides. On March 26, 2014, the Commission issued a Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief that details the Commission's findings of fact and conclusions in support of its December 20, 2013 Notice of Decision and Order.

The Public Staff believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides for at least the next one to two years. The swine waste-to-energy industry remains largely undeveloped, particularly relative to the need for approximately 92,000 MWh of swine waste energy each year in 2014 and 2015 to meet the Commission’s Order of December 20, 2013. The poultry waste-to-energy industry has somewhat more potential to produce the 170,000 MWh of energy necessary in 2014 to comply with the same Order, but the currently operating biomass power plants that have successfully utilized poultry waste fuel do not have enough combined capacity to fulfill the entire requirement. Even if these plants reach their full operational potential in 2014, they will not have enough capacity to produce the 700,000 MWh of poultry waste energy necessary to meet the 2015 requirement. The lack of swine and poultry waste-to-energy facilities is the result of: (1) limited technology development and expertise because currently North Carolina is the only state with swine and poultry set-aside requirements; (2) the utilities’ reluctance to commit to expensive purchase contracts for speculative technologies; and (3) the current uncertainty as to whether the General Assembly will alter the REPS requirements in ways that could leave the owners of these facilities with stranded costs.

PUBLIC STAFF CONCLUSIONS ON REPS COMPLIANCE PLANS

In summary, the Public Staff’s conclusions regarding the REPS compliance plans of DEP, DEC, and DNCP are as follows:

1. The compliance plans of DEP, DEC, and DNCP indicate that they should be able to meet their REPS obligations, with the exception of the swine and poultry waste set-asides, during the planning period without nearing or exceeding their cost caps.

2. The utilities will have difficulty meeting the Commission’s revised swine waste requirements in 2014 and 2015, and DEP and DEC will have difficulty meeting the poultry waste requirements, but they are actively seeking energy and RECs to meet these requirements.

3. The Commission should approve the REPS compliance plans filed by DEP, DEC, and DNCP in 2013.

The Commission concludes that the 2013 REPS compliance plans show that DEP, DEC and DNCP, as well as the electric power suppliers for whom the IOUs provide REPS compliance, are well-positioned to comply with their future REPS obligations, with the exception of the swine and poultry waste set-asides. Therefore, the Commission concludes that the 2013 REPS compliance plans filed in this docket by the IOUs and other electric power suppliers are satisfactory and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

ADDITIONAL ISSUES RAISED IN INTERVENOR COMMENTS

The Public Staff, NC WARN, NCSEA, MAREC, and SACE/Sierra Club, in their April 11, 2014 comments, raised various issues related to the IRPs and REPS compliance plans submitted by the three IOUs. Many were specific to DEC and DEP, and some comments were addressed to the IRP process itself. In their May 23, 2014 joint reply comments DEC and DEP addressed these issues, as did DNCP in its reply comments. A third set of reply comments were jointly submitted by SACE and Sierra Club. The following responses were submitted by the IOUs to the issues raised by the various parties in their comments.

DEC and DEP Responses

Public Staff Issues

A. DEC Carbon Neutrality Plan

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

As the Public Staff noted in its comments, the Commission's order approving the 2012 DEC IRP contained a requirement that DEC continue to provide updates in future IRPs to its Cliffside Unit 6 Carbon Neutrality Plan (CNP) regarding its obligations related to the Cliffside Unit 6 air permit. However, DEC's 2013 IRP update filed on October 15, 2013, did not include the

[1] Order Granting Certificate of Public Convenience and Necessity with Conditions, Docket No. E-7, Sub 790, at p. 140.

Cliffside Unit 6 CNP. Accordingly, DEC attached the CNP as a supplemental Appendix L to its reply comments filed on May 23, 2014.

In summary, the CNP shows that: (1) DEC proposes to retire up to 1299 MW of older coal-fired generation by the end of 2018; (2) DEC has allocated space at Cliffside Unit 6 to accommodate equipment potentially needed to meet future carbon reduction technologies; and (3) DEC has identified several system carbon reduction actions that DEC will implement that will exceed the approximately 5.3 million ton reduction required to make Cliffside Unit 6 carbon neutral in 2018.

The Commission concludes that DEC's Carbon Neutrality Plan should be approved as a reasonable plan for compliance with the Cliffside Unit 6 air permit conditions. However, this approval does not constitute Commission approval of the activities shown in DEC's Carbon Neutrality Plan or expenditures for those activities.

B. Interconnection and QF Information

DEC and DEP in their reply comments, and future IRPs, should provide both information on the number and resource type of the facilities currently within the respective utility's interconnection queue and a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

In their joint reply comments, DEC and DEP stated that, if requested by the Commission in the Order on this IRP, the Companies will include the requested information on the interconnection queue in future IRP filings. As of April 30, 2014, DEC and DEP have the following potential projects in their interconnection queue:

"In Queue" Qualified Facilities – as of April 30, 2014

	State	Energy Type	Number of Customers	Total Capacity (MW AC)
DEC	NC	Biomass	3	8.70
		Hydro	3	31.51
		Solar	132	754.92
	NC Total		138	795.13
	SC	Hydro	1	0.25
	SC Total		1	0.25
DEC Total			139	795.38

DEP	NC	Biomass	4	8.45
		Hydro	2	1.55
		Landfill Gas	3	17.75
		Solar	243	2297.07
	NC Total		252	2324.81
	SC	Biomass	1	73.00

		Solar	4	142.31
	SC Total		5	215.31
DEP Total			257	2540.12
Grand Total			396	3335.49

With regard to the potential impact of the projects in the interconnection queue on the DEC and DEP resource plans, it is the Companies' position that each Company's REPS compliance plans, as included in the 2013 IRP updates, are the best estimate of renewables adoption at this point in time. The plans reflect careful examination of the current interconnection queue and estimation of how much renewable capacity could be cost effectively converted to compliance resources. Based on this review, the Companies' 2013 IRP updates only utilized existing executed renewable contracts along with enough future renewable resources required to meet mandatory renewable targets under REPS, as well as a proxy for a future renewable energy standard for South Carolina beginning in 2018. Additional renewable resources are possible, but subjective, and as such are not appropriate for inclusion in the Companies' base resource plans. For planning purposes, DEC and DEP must ensure that they can meet peak load demand without relying upon on speculative unexecuted non-utility resources. Given DEC and DEP's experience with renewable projects proposed by developers, the utility cannot depend on potential projects that are in excess of its targets set in the above planning assumptions. As explained in the late filed exhibit in the recent avoided cost proceeding (Docket No. E-100 Sub 136), historically DEC and DEP have seen approximately twenty-five (25%) of the capacity in the interconnection queue come to fruition. When viewed in the aggregate between DEC and DEP, this completion rate applied to the current interconnection queue would not exceed the REPS compliance plan for the IRP planning horizon.

The Commission agrees with the Public Staff that DEC and DEP's QF interconnection queue information has important value going forward. The number of QF interconnection requests, especially for solar, has increased exponentially and this queue has the potential to have a significant impact on the generation planning process. Therefore, DEP and DEC in future IRPs should provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

C. Changes to IRP Process

DEC and DEP noted that the Public Staff's comments included discussion and inquiry regarding potential modifications to the IRP process and filing calendar that may be reasonable. The Companies' observation is that IRP process has expanded in scope over time through incremental annual IRP rulings, along with a growing number of special interest group intervenors participating in the IRP process. This is not surprising because the IRP essentially incorporates many facets of the utility business including energy efficiency, renewables compliance, fuel forecasts, new plant development, environmental compliance strategies, load forecasting, etc. Most of these intervenors focus only on issues of importance to their members or stakeholders, but lack the obligation for the provision of reliable power delivery and the obligation for least cost planning on behalf of all of DEC and DEP's customers that the IRP planning process requires. To a large extent many of the individual issues now being raised by intervenors within the context of an IRP docket have their own focused regulatory proceedings. For example, the IRP clearly has overlap with EE, REPS, fuel, CPCN, avoided cost and rate case proceedings. However, the IRP was never intended to supplant or supersede these more focused proceedings. Rather, the IRP process by its very nature is a planning process only that provides insights into factors that influence the utilities' future resource plans. To a large extent several of the recommendations expressed by intervenors in their IRP comments are the same recommendations made within the context of the more focused proceedings. To some degree, this moves the IRP process away from a big picture, long term planning process toward more of a shorter term operational focus. Should the Commission wish to consider refocusing the IRP to its original intent by moving to a bi-annual process or some other variation of an IRP process modification DEC and DEP would be supportive of working toward productive revisions to the process.

The Commission understands the time and complexity concerns that the parties have with the current IRP planning process. Between the time extension requests and the increasing complexity of the issues raised during the proceedings, it makes for drawn out IRP timelines. The Commission agrees that some modifications might be warranted, especially to these odd-year annual update proceedings. For this reason, the Commission intends to open a future docket which will request comments and reply comments on the specific issues of what might be done to streamline the annual update reporting process so that it does not simply become another biennial proceeding with a different name.

D. Environmental Analysis

DEC and DEP argued that the companies' IRPs include resource plans that comply with all known federal and state level environmental laws. Fixed and variable environmental compliance costs required for regulatory compliance are included and appropriately considered in the IRP planning process. The IRPs not only include the quantitative aspects of environmental compliance, but also include an extensive qualitative discussion surrounding existing and pending environmental regulations. Given the extent to which the Companies already consider environmental compliance in the IRP process, DEC and DEP do not believe that additional prescription concerning specific methods by which to incorporate environmental compliance costs are warranted. The Commission finds that no additional steps are required at this time.

E. Decommissioning Costs

DEC and DEP explained that decommissioning costs for existing coal, nuclear and gas units do not have a direct influence on the Companies' future expansion plans. Ultimately, these costs are sunk costs associated with exiting unit retirements and do not influence the selection of the future resource portfolio. Costs associated with the retirement of existing generating units that have been in service for many decades have existing mechanisms in place for review and cost recovery. Requiring the IRP process to address decommissioning costs of existing units will not alter the resource planning process, nor the selected expansion plan. While a consideration of decommissioning costs may have merit in appropriate dockets or proceedings, DEC and DEP assert that the IRP process is not the appropriate place to address this issue. The Commission agrees with DEC and DEP.

F. Quantifying Generation Diversity Benefits

The Public Staff recommends that the Companies develop a quantification method for fuel diversity as part of the IRP process. The Companies believe that recommendation is already captured as part of the existing IRP process commensurate with Commission Rule R8-60. The Companies' current IRP practices include modeling multiple sensitivities around fuel prices. Furthermore, the Companies show how different resource portfolios perform under these varying fuel prices. Both the quantitative impacts and the qualitative benefits of fuel diversity are fully presented in the IRPs. The Public Staff does not provide a specific recommendation as to what other quantitative metric or method they are recommending and as such it is difficult to ascertain the merits of such additional analysis. DEC and DEP believe that the current approach that both quantitatively and qualitatively addresses fuel diversity is fully adequate. The Commission finds that no further action is required at this time.

<u>NCSEA Issues</u>

DEC and DEP state that in its IRP comments, NCSEA does not appear to have any real criticism of the DEC and DEP IRP updates, and instead finds the Companies' increased diversification into renewable energy resources, including DSM/EE, to be "promising." NCSEA makes some unique policy suggestions, such as asking the Commission to "reaffirm the foundational importance" of the IRP proceeding, to which the Companies will not reply. NCSEA asks the Commission to endorse consistency across proceedings, and discusses assumptions used in the IRP and avoided cost proceedings. DEC and DEP strive for consistency in the underlying assumptions and methodologies used in their various proceedings, and have noted their post-merger emphasis on developing consistency and best practices where applicable. As an example, the avoided energy and avoided capacity values used in DEC and DEP's EE/DSM rider proceedings are taken directly from the IRP. NCSEA also asks that the utilities concisely state in one place in their IRPs "all of the key policy assumptions" which underlie its base case or recommended plan. DEC and DEP assert that their IRPs do explain the policy assumptions contained therein.

NCSEA also commented on DEC and DEP's "aspirational" 15 EE savings performance targets as contained in a settlement agreement filed with the Public Service Commission of South Carolina, and asks the Commission to push the Companies to innovate to meet their aspirational goal by encouraging collaborative efforts to develop new EE programs and measures, such as combined heat and power (CHP). The Companies note that related issues were already agreed to as part of the Stipulation and Agreement filed in Docket No. E-7, Sub 1032 and agreed to in Docket No. E-2, Sub 1030, and in fact a Duke Energy Collaborative meeting where CHP was discussed has already been held. Finally, NCSEA also raises an issue unrelated to the IRPs - -facilitating third party access to private customer usage data. NCSEA asks that the Commission require utilities to provide online forms for customers to authorize disclosure of their usage information to third parties. DEC and DEP responded that perhaps NCSEA is not aware, but DEC and DEP do have an online "Energy Data Request Form," for independent third parties with a need to use customer data. This website allows third parties to identify themselves and provide details about the specific data they seek. After completing the online form, such third parties are contacted electronically by Duke Energy with information about the process and requirements, including the cost of data, and are provided an electronic copy of the Duke Energy customer data release form. This process was developed with the Companies' Code of Conduct in mind and to ensure a consistent and cost-effective approach for handling third party requests. DEC and DEP assert that the current process works well.

As to the Companies' REPS Compliance Plans, NCSEA asks that the Companies be required to submit one-sentence certifications that prior REPS compliance plan reviews have been conducted, unless this is obvious from the filing of a revised past REPS compliance plan with redactions removed. DEC and DEP would not object to such a Commission requirement.

NCSEA also requests that the Commission require the utilities to create avoided cost projections in their 2014 REPS compliance plans using the methodological approaches approved in the 2012 avoided cost order, together with a statement from DEC and DEP indicating whether the effect of the JDA was incorporated. DEC and DEP pointed out that first, the Commission's February 21, 2014 Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 136 discussed the use of avoided costs in REPS Compliance Plans and held in Finding No. 18 that, "DEC and DEP henceforth should include actual projected avoided cost rates as of the date of the Compliance filings.” Second, the Commission's rules already require the utilities to include the current and projected avoided cost rates for the years of the subject plan, so NCSEA's recommendation is all the more duplicative and unnecessary. See Rule R8- 67(b)(1)(v). Third, DEC and DEP's position is that avoided cost calculations are subject to their own regulatory proceedings in which stakeholders have opportunity for substantial input. In fact, NCSEA is a party to the currently pending Docket No. E-100, Sub 140 proceeding, wherein the Commission is examining the methodological approaches utilized in the 2012 avoided cost proceeding for the 2014 avoided cost proceeding. Filing avoided cost projections in the REPS Compliance Plans on September 1, 2014, based on 2012 methodologies that are currently under review could result in outdated and inaccurate projections.

The Commission is satisfied with the responses of DEC and DEP to these issues raised by NCSEA.

<u>MAREC Issues</u>

DEC and DEP stated that, as in its 2012 IRP comments, MAREC, a non-profit formed to advance renewable energy development primarily in the PJM Interconnection markets, makes the general allegation in its comments that DEC and DEP did not adequately consider wind energy in their IRPs. MAREC notes that DEC and DEP should not have been expected to comply with the Commission's requirement to consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, because that requirement was included in the Commission order approving the 2012 IRPs and issued the day prior to the filing of the DEC and DEP 2013 IRP updates. DEC's 2013 IRP update base case includes 849 MW of renewable resources by 2018 and 2,028 MW by 2028, which includes 150 MW of wind. DEP's 2013 IRP update base case includes 297 MW of renewable resources by 2018 and 802 MW by 2028, which includes 100 MW of wind. MAREC does not appear to appreciate, however, that both Companies' 2013 IRP updates also included an Environmental Focus Scenario (EFS), which evaluated an assumed requirement to serve approximately 8% of each Company's combined retail load with new renewable resources by 2028-- which represents approximately twice the amount of renewable energy as compared to the base case. The DEC EFS included 758 MW of nameplate wind and the DEP EFS included 505 MW of nameplate wind. The purpose of the scenario is to show how the Companies' resource plans would be affected in the event that additional cost-effective renewable and energy efficiency resources are identified or mandated. A key takeaway is that, in such an event, some traditional resources can be eliminated or deferred but significant levels of traditional resources such as new nuclear and natural-gas combined cycle are still needed.

In their joint reply comments, DEC and DEP argued that they have adequately considered wind and all other potential renewable energy resources in preparing their 2013 IRP updates. Duke Energy Corporation, the parent company of DEC and DEP, is one of the largest wind energy developers in the United States and recognizes the valuable potential that new wind energy resource development can provide. In their IRPs, however, DEC and DEP analyzed wind and other generation technologies and selected the resource plans that best met the Companies' needs to provide the reliable, least-cost resource mix as required by North Carolina's integrated resource planning and REPS laws.

MAREC also contended that the Companies should include a new annual RFP process that would solicit new renewables. Both DEC and DEP explained that they regularly assess the market place for competitive wind and other renewable resources, including through formal RFPs or the receipt of unsolicited bids. On February 14, 2014, DEP and DEC issued a RFP for 300 MW of new solar energy capacity to allow DEP and DEC to further their commitments to renewable energy, diversify their energy mix and meet their REPS requirements. Accordingly, they argue MAREC's proposed RFP requirement is unnecessary.

The Commission finds that no further action is required by DEC and DEP in response to the issues raised by MAREC.

<u>SACE and Sierra Club Issues</u>

DEC and DEP responded that, in their comments, SACE and Sierra Club generally critique the Companies' inclusion of EE and renewable resources, and without offering their own proposed mix of least cost and reliable resources, assert that the resource plans contained in the Companies' IRP update are inadequate. As set forth in detail below, DEC and DEP stand by their IRP methodologies and analyses of both supply and demand side resources and the selected plans contained in the 2013 IRP updates.

A. The Companies' Appropriately Evaluated and Included EE and Renewables in their 2013 IRP updates.

DEC and DEP commented that while noting that DEC "led the Southeast in energy savings from efficiency," in both 2011 and 2012, as in previous IRP comments, SACE and Sierra Club allege that DEC and DEP asserted that they are not planning to capture all cost-effective EE and maximize renewable energy opportunities. DEC and DEP have included significant levels of EE and renewable resources in their 2013 IRPs updates, surpassing the levels included in the 2012 IRPs. As to EE, DEC projects that it will have delivered over 10,510,000 MWh of EE savings between 2009 and 2028. The estimated peak load impact of these EE savings is 1,734 MW in that same timeframe. In addition, DEC projects over 1,060 MW of peak load savings from DSM programs by 2028. DEP projects that it will have delivered 4,403,000 MWh of EE savings between 2009 and 2028. The estimated peak load impact of these EE savings is 1,068 MW in that same timeframe. In addition, DEP projects 789 MW of peak load savings from DSM programs by 2028.

The Companies explained that they have included in their 2013 IRP updates the level of EE they believe is reasonably achievable and economic. In response to a data request seeking the feasibility assumptions of the increased EE levels asserted in their comments, SACE and Sierra Club admitted that they did not conduct a market potential study or make assumptions regarding participation (penetration) rates, or technology to achieve penetration rates, for purposes of preparing their comments, but that their comments were "informed" by their review of market potential studies performed for DEC and other southeastern electric utilities. DEC and DEP asserted that SACE and Sierra Club do not appear to realize that potential does not equal cost-effective or achievable. In their comments criticizing DEC's EE cost assumptions, SACE and Sierra Club rely upon the Lawrence Berkeley National Laboratory Study by Galen Barbose. While this study does make an attempt to adjust cost projections for size of first year impacts, it does not adjust for cumulative market penetration (i.e., the more that has been achieved on a cumulative basis, the higher must be the costs per kWh achieved). Furthermore, the study essentially relies on past spending and impacts to make its projection, which DEC and DEP assert is a very unreliable methodology.

DEC and DEP pointed out that SACE and Sierra Club complain about the EE costs assumed by the Companies in their 2013 IRP updates which deserves a brief response. On pages 27-28 of their comments, SACE and Sierra Club note four alleged flaws with DEC's EE cost assumptions and methods. As to the use of the 60% market saturation, this is based upon the market potential study prepared for DEC and is consistent with reasonable adoption curves for typical measures. As to the criticism that there is no provision for introduction of new EE technology or for reduction in costs of future EE technology, SACE and Sierra Club's comments ignore that generation technology is treated exactly the same way in the IRP (no assumptions are made that generation technology costs will decrease over time). As to their assertion that economies of scale serve to reduce EE program costs as more customers participate, DEC and DEP argued that this ignores the reality of EE program implementation: as less expensive EE measures are depleted (the "low hanging fruit"), more expensive measures must be offered. Finally as to the criticism of the 30% program overhead costs, this is a legitimate program expense (and which is approved through the cost recovery mechanism) based on the market potential study, that must be included or the total utility costs to implement EE will be understated. SACE and Sierra Club have a final criticism that the Companies' long-term EE cost forecast indicates cost escalation in excess of the rate of inflation. Again, these intervenors ignore the fact that as an initial low cost EE resource reaches its market potential, as in generation dispatch, the utility has to move "up the stack" to the next higher cost EE resource. The two drivers of costs are inflation and the incremental cost of the next EE resources. It is axiomatic, therefore, that the combination of these two factors will result in the projected increase in the unit cost of EE exceeding the rate of inflation.

DEC and DEP further noted that SACE and Sierra Club propose a list of EE programs that the Companies should consider. In response to a data request, these intervenors revealed that they "did not review the program costs, program participation, or perform participation studies" as to their proposed programs. As to specific EE programs, DEC and DEP have collaborative groups which discuss and vet all programs and would welcome the opportunity to discuss these programs at their collaborative groups. DEC and DEP have a bias toward EE, which is reflected in the IRP process by putting EE ahead of other resources and locking in the programs and impacts before any additional generation resources are considered. DEC and DEP make their projections of EE impacts in conjunction with an independent assessment of the market potential for EE for each utility's service territory, a critical component that cannot be overlooked.

B. SACE and Sierra Club's Environmental Compliance Cost Analysis and Resulting Conclusions are Flawed

According to DEC and DEP, in their comments SACE and Sierra Club also allege that their "analysis" of future environmental requirements "strongly suggests that retirement of a minimum 5,000 MW of coal capacity is likely to be the most cost-effective solution." In response to data requests, however, SACE and Sierra Club responded that they had not performed any analysis of which coal units DEC and DEP should retire or when. Appendix G to both th DEC and DEP 2013 IRP updates contains extensive discussion of potential future environmental requirements that will impact the Companies' operations in the coming years, including those related to the Cross-State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule, the Mercury and Air Toxics Standard (MATS), National Ambient Air Quality Standards, SO_2 Standards, Particulate Matter Standard, Greenhouse Gas Regulation, Cooling Water Intake Structures (CWA 316(b)), Steam Electric Effluent Guidelines, and Coal Combustion Residuals. The Companies' IRP models build in all known capital and O&M costs for environmental compliance. SACE and Sierra Club assert reliance upon a Coal Asset Valuation Tool (CAVT), which incorporates assumed environmental costs. All of DEC and DEP's coal units already have FGDs (or scrubbers), SCRs or SNCRs or baghouses, with the exception of the Lee Steam Station in South Carolina, which is scheduled for retirement in 2014 (and conversation of one unit to natural gas in 2015). As a result, DEC and DEP believe that their remaining coal units are compliant with MATS and CSAPR.

DEC and DEP asserted that SACE and Sierra Club's coal retirement analysis based upon the CAVT tool understates replacement generation costs and overstates future environmental compliance costs, which results in invalid conclusions. Based upon SACE and Sierra Club's responses to data requests, the Companies note that the future environmental control costs represented by the "medium scenario" of the CAVT tool relied upon by these intervenors are not representative of the Companies' expected outcome with MATS and 316(b) requirements. According to the CAVT information provided, it appears that costs for baghouses (except for Cliffside 6), activated carbon injection (ACI), Cooling Towers (except Mayo, Cliffside 5 & 6) were included for all DEC and DEP units. As noted previously, Duke Energy has tested all coal units for compliance with MATS and compliance can be met without the installation of baghouses and with limited ACI injection at Allen and Marshall 4. Also based on the 316(b) rule finalized in May 2014, cooling towers are not anticipated to be required. An example of the impact of SACE and Sierra Club's inclusion of baghouses, ACI and cooling towers is the overstatement of more than $1 Billion (in $2012) in environmental compliance costs for DEC's Belews Creek Steam

Station alone. Accordingly, DEC and DEP argue that SACE and Sierra Club's assumptions regarding future environmental costs for the Companies' are invalid and their resulting conclusions must be disregarded.

The Commission is satisfied with the responses of DEC and DEP to the issues raised by SACE and Sierra Club.

DNCP Responses

Public Staff Issues

In its May 23, 2014 reply comments, DNCP stated that it agrees to most of the Public Staff's recommendations as they relate to the company. DNCP did, however, provide specific responses to six of the Public Staff's recommendations.

A. Biomass Conversions

The Public Staff noted that conversion of the Hopewell, Altavista, and Southampton Coal Stations to biomass-fueled facilities was scheduled to be implemented before the end of 2013. The Public Staff sought confirmation that these conversions were, in fact, completed during 2013. DNCP, in its reply comments, stated that it completed conversion of the above-referenced facilities to biomass on the following schedule:

Plant	Commercial Operation Date
Altavista	7/12/2013
Hopewell	10/18/2013
Southampton	11/28/2013

B. Extending Future Planning Period to 20 Years

The Public Staff recommended that "the planning period for future IRPs that foresee substantial nuclear retirements be at least 20 years." DNCP currently uses a 25-year Study Period (e.g., 2014-2038 in the 2013 Plan) and displays text, numbers, and appendices for a 15-year Planning Period (e.g., 2014-2028 in the current 2013 Plan). As explained in the 2013 Plan, the Company's customers today benefit substantially from the Company's prior investments in the four nuclear units, at North Anna and Surry, and the Company is mindful of the scheduled license expirations of these units between 2032 and 2040. However, DNCP notes that Commission Rule R8-60(c) and (h) direct the Company to present its IRP using a 15-year planning period. Further, the Company notes that its odd-year Virginia IRP filing is based on a 15-year Planning Period, and is filed pursuant to Va. Code§ 56-592 et seq. and the Virginia State Corporation Commission's Integrated Resource Planning Guidelines. The Company prefers to maintain consistency between the North Carolina and Virginia IRP filings (which both require 15-year planning periods) and, therefore, disagrees with presenting the IRP based on a 20-year planning period. However, upon request during discovery, the Company will provide the Public Staff with all the requisite information contained in the 25-year Study Period analysis, which should provide the Public Staff with the information sought.

The Commission is satisfied with the IOU's current 15-year planning periods. However, the IOU's should always supply additional forward looking comments in their IRPs when warranted to provide adequate background concerning critical infrastructure decisionmaking.

C. Quantifying Fuel Diversity Value

The Public Staff recommends that the utilities "continue to develop methods of quantifying the benefits of fuel diversity" and requests the utilities provide detailed support in future IRPs if a utility selects a fuel diversity plan over a plan that is otherwise lower in costs. Specifically, the Public Staff requests the utilities develop a "metric to quantify the value of diverse generation portfolios" such as the present value revenue requirement (PVRR) method.

DNCP noted that its 2013 Plan does not select its Fuel Diversity Plan over the least cost Base Plan. Instead, the Company recommends a path forward based upon the least-cost Base Plan, while concurrently continuing forward with reasonable development efforts of the additional resources identified in the Fuel Diversity Plan. As with any strategic plan, the Company will update its future Plans to incorporate new information as it becomes known.

In response to the Public Staff's specific recommendation to establish metrics to quantify the benefits of fuel diversity, DNCP agrees that more purposefully assessing the benefits of fuel diversity in future planning processes is a reasonable goal. Fuel diversity considerations represent increasingly important risk trade-offs between generally higher long-term operating cost risks under the Base Plan versus higher near-term project development cost risks under the Fuel Diversity Plan. The importance of quantifying this risk trade-off also increases as the percentage of gas-fired generation selected as the least- cost option in the Company's Base Plan trends higher. The Company agrees to further analyze this risk-trade off and to develop potential metrics to quantify the benefits of fuel diversity prior to filing its 2015 IRP update filing. The Company is also willing to work with the Public Staff in the coming months to develop appropriate analytical metrics that allow for quantification of the benefits of fuel diversity.

DNCP does, however, disagree with the Public Staff's further recommendation that PVRR should be used to represent the value of fuel diversity in the Company's future Plans. While the Public Staff's comments suggest that it has "no clear preferred method" to quantify fuel diversity at this time, this methodological ambivalence quickly transitions into a recommendation that the utilities graph PVRR for their resource portfolios by various scenarios similar to the Tennessee Valley Authority's (TVA) approach in its March 2011 IRP. The Company has reviewed the TVA approach to graphing PVRR, and would submit that this approach provides little additional value in assessing the risk of a given portfolio. Cost risk is assessed based on how a given portfolio performs relative to a base case under a series of scenarios and sensitivity cases. This is precisely what is reflected in the 2013 Plan. What is important is the difference between the base case PVRR cost and the PVRR of the scenario or sensitivity case in question. The absolute value PVRR in and of itself offers little relative insight.

DNCP also disagrees with the Public Staff's related recommendation that the utilities should estimate the annual rate impacts of their various plans over the life of the planned resource additions. While an estimate of annual rate impacts of resource additions on a levelized per kWh basis may provide some understanding of ratepayer impacts, the Company believes this value would be limited in comparison to the way bill impacts are provided in base rate, fuel, DSM and other ratemaking proceedings. In addition, the Company is concerned that such an additional requirement may be a source of confusion for customers since DNCP is not asking for actual cost recovery in the IRP proceeding.

In sum, while the Company disagrees with the Public Staff's specific recommendation to follow TVA's approach to presenting PVRR in analyzing its future Plans, the Company does agree in principle that quantifying the benefits of fuel diversity in its future Plans is of increasing importance and commits to provide appropriate metrics to show this analysis in its 2015 IRP update filing.

The Commission is satisfied with DNCP’s response.

D. Anticipating Environmental Regulatory Constraints Impacting Planning

The Public Staff recommends that the 2014 and future IRPs "include an economic analysis of the costs of compliance with pending environmental regulations, both individually and in combinations, and an environmental compliance scenario that includes reasonable assumptions regarding the costs of compliance." The Company would like to clarify that its 2013 Plan (and prior Plans) do, in fact, consider both "effective and anticipated U.S. Environmental Protection Agency (EPA) regulations concerning air, water, and solid waste constituents." DNCP’s planning process not only evaluates the risks associated with effective and anticipated EPA regulations, but also analyzes the cost of compliance with anticipated environmental regulations in developing all of its planning scenarios. Section 3.1.3 of the Company's 2013 Plan recognizes the effective and anticipated EPA regulations that DNCP considered in developing its Plan (as set forth in DNCP's Figure 3.1.3.1 cited to on page 68 of the Public Staff’s comments). The Company's 2013 Plan then noted that the Company's 2012 Plan comprehensively reviewed and analyzed the costs to retrofit units with new environmental control equipment, repower units to natural gas, convert units to burn biomass as a fuel source, or retire the units from service. DNCP's 2013 Plan remains largely unchanged compared to its 2012 Plan regarding the costs of retrofitting, repowering, and retiring units affected by EPA regulations. However, the Company's Plan does update expected installation of environmental controls on Yorktown 3 and Possum Point 5, which have been delayed and will both be implemented in 2018.

As the foregoing shows, the potential economic impacts of both effective and anticipated EPA regulations on DNCP’s current generating units and future planning scenarios are fully considered in the Company's planning process. The Company will continue to take this approach and will continue to provide the economic analysis through discovery supporting its planning scenarios to the Public Staff in the future. This includes the reasonably anticipated and quantifiable cost of ensuring its current generating unit options as well as planned resource options can comply with anticipated environmental regulations. The Company does, however, note that the focus of its planning process is on "resource planning"- meaning evaluating prudent and least- cost supply-side and demand-side resources available to reliably serve its customers- and is not designed to solely develop cost estimates of compliance with prospective individual environmental regulations.

Based on the foregoing, DNCP will continue its comprehensive approach to evaluate the cost of current and anticipated EPA regulatory compliance in its future resource planning process and urges denial of the Public Staff's recommendation as unnecessary.

The Commission finds that no further action is required.

E. Inclusion of Decommissioning Costs

The Public Staff recommends that the utilities "include the decommissioning costs associated with each resource type, including coal, nuclear, natural gas, and renewable resources in one or more of the scenarios evaluated." DNCP generally agrees that inclusion of material decommissioning costs in the development of its future resource plans is reasonable where such decommissioning costs are currently quantifiable and not de minimis. In its ongoing development of its 2014 Plan, the Company plans to recognize decommissioning costs associated with potential new nuclear, offshore wind, and onshore wind resources included in that Plan, as those resource options present quantifiable and non-de minimis decommissioning costs. Other future resource options including coal, natural gas, and solar/non-wind renewables are projected to be "decommissioned-in-place," and are not currently expected to cause material decommissioning costs in substantial excess of potential salvage value of the unit at the time of unit shut down. DNCP will continue to evaluate all future resource options to assess whether material decommissioning costs should be recognized in future Plans.

The Commission is satisfied with DNCP's response to this issue.

F. Stakeholder Participation and Streamlining IRP Update Process

The Public Staff makes recommendations about how the IRP process could be improved. First, the Public Staff suggests that the Commission solicit comments from the parties regarding changes to the IRP process to make it more "robust and meaningful." Second, the Public Staff advocates allowing stakeholder input prior to development of the IRPs by the utilities. Finally, the Public Staff suggests the Commission may wish to consider issuing expedited rulings on key inputs and assumptions to be included in the next IRP filing to be made by September 1, 2014.

In response to the Public Staff's first suggestion, DNCP noted that the current IRP process was established through revisions to Rule RS-60 approved on July 11, 2007 and reflected a consensus between the Public Staff, the utilities, and numerous other stakeholders regarding the structure of the revised IRP rule and process. The Company would welcome the opportunity to comment on the IRP process with any eye towards streamlining the IRP update in North Carolina (the odd-year filing) to make it less burdensome on the Company. DNCP noted that its resource planning process is an ongoing process designed to meet its biennial resource planning responsibilities in both Virginia and North Carolina. Because, by statute, the Company's IRP filing in Virginia is due on September 1 of each odd year, a streamlined update proceeding in North Carolina while the Company is supporting a fully-litigated proceeding in Virginia would help maximize and conserve the Company's planning resources.

Regarding stakeholder participation in the development of the Company's IRP, DNCP does not believe a "North Carolina-wide" stakeholder process is necessary or would benefit each of the utilities mandated to separately develop their own resource plan to serve its customers' future electricity needs. Development of DNCP's IRP is obviously a distinct process from DEC's or DEP's planning process. That said, the Company does not oppose allowing up front input into its own resource planning process arid, in fact, has had a stakeholder review process (SRP) in place in Virginia for several years. The Public Staff, Southern Environmental Law Center, Sierra Club and others routinely participate in the SRP and this forum could be made to be open to other interested parties from North Carolina as well.

Finally, regarding the Public Staff's recommendation that the Commission consider expedited rulings mandating the Utilities include "key inputs and assumptions" in their 2014 Plans, the Company has already began its 2014 Plan development process and is concerned that any ruling that is entered now by the Commission will not be able to be implemented in time for the 2014 Plan filing. Therefore, DNCP recommends the more prudent course is for the Commission to give due consideration to all the recommendations and comments received and issue a comprehensive ruling in due course that the Utilities can incorporate into their 2015 Plan filings.

The Commission's response to this IRP streamlining issue was discussed in the DEC/DEP comments section.

NCSEA Issues

A. Relationship to Avoided Cost Proceeding

DNCP, in its reply comments, argued that NCSEA's request for a "Commission endorsement" of "consistency across proceedings," is not necessary or appropriate. While the Company generally agrees that reasonable consistency is a laudable purpose and, in most instances, is appropriate, a formal statement such as NCSEA requests would ignore the distinct purposes of biennial avoided cost proceedings as opposed to IRP proceedings. Moreover, such a statement would unnecessarily restrict the utilities in developing their IRPs and avoided cost rates such that they could not account for those instances when consistency is either not possible or not reasonable under the circumstances. Finally, given that NCSEA and any other party may challenge IRP data inputs and avoided cost rates in their respective proceedings, it is unnecessary for the Commission to take this step.

DNCP further commented that, as NCSEA noted, the Commission has already rejected arguments similar to those made by NCSEA here. In its May 30, 2013 Order in DEP's 2012 general rate case, the Commission recognized that its responsibilities under the Public Utility Regulatory Policies Act of 1978 (PURPA) to set the utilities' avoided costs are functionally distinct from its ratemaking functions under Chapter 62. DNCP submits that the Commission's statutory resource planning process is also functionally distinct from the PURPA avoided cost rate-setting process. This is because the precision required to ensure the Utilities are meeting PURPA's goals of promoting the development of small power producers is fundamentally different than the Commission's oversight of long-term resource planning. Under PURPA, the Commission is prohibited from directing the utilities to pay QFs more than avoided cost. Recognizing the great importance and highly technical nature of this determination, the NCUC has initiated the 2014 avoided cost proceeding in Docket No. E-100, Sub 140, to consider whether refinements to the methodologies and calculations underlying the utilities' avoided costs are needed. In contrast to the mandated precision required to develop the utilities current avoided costs and promote efficient QF development, the Commission's long-term resource planning process is an evolving and dynamic process focused on the "probable future" generating needs of the State. Given the substantially different purposes of these two proceedings, while similar inputs may be used, where appropriate, to develop the utilities' avoided cost rates as are used in resource planning proceedings, justifiably reasonable differences may exist between the data used in the IRP proceeding and in the avoided cost proceedings.

For example, DNCP points out that an after-the-fact discovery of error or a demonstrated change in circumstances from those contemplated during the preparation of an IRP may result in the inputs and assumptions used for the IRP to be inappropriate for use in a utility's determination of avoided cost rates. NCSEA's proposal would result in utilities being unable to account for such changes and could result in inaccurate and potentially unlawfully excessive avoided cost rates.

In addition to being inappropriate, DNCP argues that no preemptory Commission endorsement of consistency is needed. If NCSEA or any other party concludes that data inputs used in either an IRP proceeding or an avoided cost proceeding are unreasonable, it would assuredly have a full and fair opportunity within the context of that specific proceeding to challenge the reasonableness of the IRP or avoided cost data for ultimate resolution by the Commission.

The Commission appreciates NCSEA's comments concerning consistency across multiple Commission proceedings. The Commission agrees that such consistency, where feasible, can be helpful in understanding components of multiple proceedings when the components remain static. However, the timing of the Commission's proceedings varies, and that variance can cause facts and projections to change from one proceeding to another. That point is often illustrated by the two proceedings that NCSEA used as an example, the IRP and the biennial avoided cost dockets. In particular, NCSEA cited the assumptions and projections made by the utilities regarding CT costs and capacity needs.

In the present docket, the utilities filed their IRPs in October 2013. On the other hand, the utilities' testimony in the current avoided cost docket, E-100, Sub 140, was not filed until April 2014. Assumptions and projections about material facts, including CT costs and capacity needs, can change over the span of several months. The Commission endorses consistency in information and projections across multiple proceedings, where appropriate. But more importantly, the Commission endorses the use of timely and accurate information in all proceedings.

B. Policy Landscape Assumptions

NCSEA recommends that the utilities "be required to concisely list in one place in its filed plan all of the key policy assumptions which underlie its "base case or recommended plan." DNCP respectfully responds that the policy and other assumptions underlying its 2013 Plan are already appropriately set forth in the Introduction and Chapter 1 Executive Summary and then articulated in greater detail throughout the remainder of its 2013 Plan. The Company's development of its 2013 Plan is fully consistent with the Commission's prior direction and the requirements of Rule R8-60(b). Unless a more precise explanation would assist the Commission in satisfying its statutory obligation to report to the Governor and the General Assembly, DNCP submits that nothing further or different should be required in presenting its future Plans.

The Commission finds that no changes are required at this time.

C. Customer Data Access

NCSEA notes that the Commission could encourage data access for the benefit of DNCP's customers by requiring the Company to make its data access form available electronically. The Company is working to make this form available electronically in the near future.

D. Request for Historical REPS Plan Review Certification

NCSEA recommends that each of the utilities be obligated to submit a letter verifying that they have reviewed their 2009 REPS Plan and then to include in future REPS compliance plans a certification that the historical review has been conducted. While the Company is not necessarily opposed to this requirement in its future plans, DNCP's cover letter submitting its 2013 Plan (in which the Company's 2013 REPS Plan was filed as NC Addendum I) stated:

> In accordance with Ordering Paragraph (3) of the Commission's June 3, 2013 Order Granting in Part and Denying in Part Motion for Disclosure, the Company has reviewed its 2009 REPS Compliance Plan filed in Docket No. E-100, Sub 124, and, as no information contained in that filing was designated confidential qualifying as "trade secret" under N.C.G.S. § 66-52(3), there is no information to disclose as no longer requiring such designation.

DNCP has satisfied the Commission's prior direction from the above-referenced Order, and will continue to do so. Therefore, this recommendation for a specific certification is unnecessary. The Commission agrees with DNCP.

<u>MAREC Issue</u>

Proposed Competitive Renewables Solicitation

MAREC advocates that the Commission should obligate the utilities to engage in a competitive solicitation for new renewables to satisfy their REPS obligations. DNCP disagrees. First, DNCP does not require in-state RECs to meet its REPS obligation. Second, the Commission's resource planning process pursuant to G.S. 62-110.1(c) is not designed to "alter a given utility's operations" but, instead, should resemble "a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions may be made at a later time." Thus, MAREC's recommendation to mandate a competitive solicitation for renewables should be rejected as unnecessary and outside the scope of this proceeding. The Commission agrees with DNCP.

IT IS, THEREFORE, ORDERED, as follows:

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

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

3. That the 2013 REPS compliance plans filed in this proceeding by the IOUs are hereby approved.

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

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

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

7. That the IOUs should continue to monitor and report any changes of more than 10% in the energy and capacity savings derived from DSM and EE between successive IRPs, and evaluate and discuss any changes on a program-specific basis. Any issues impacting program deployment should be thoroughly explained and quantified in future IRPs.

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

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

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

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

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

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

14. That future IRP filings by DEP and DEC shall provide information on the number, resource type and total capacity of the facilities currently within the respective utility's interconnection queue as well as a discussion of how the potential QF purchases would affect the utility's long-range energy and capacity needs.

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

16. That NC WARN's motion for an evidentiary hearing shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the ___30th___ day of June, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2014	)))	ORDER SETTING AVOIDED COST INPUT PARAMETERS

HEARD: Monday, July 7, 2014, at 1:30 p.m., Tuesday, July 8, 2014, at 9:00 a.m., Wednesday, July 9, 2014, at 9:00 a.m., and Thursday, July 10, 2014, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

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

APPEARANCES:

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BY THE COMMISSION: These are the 2014 biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 18 U.S.C.A 824a-3, and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions,[1] which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings also are held pursuant to G.S. 62-156, which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this

[1] FERC Stats. & Regs. 30,128 (1980) in Docket No. RM79-55 (Order No. 69), see also 45 Fed. Reg. 12,214 (1980).

Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

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

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

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

On February 25, 2014, the Commission issued its Order Establishing Biennial Proceeding and Scheduling Hearing. For the purpose of considering various issues raised in the 2012 avoided cost proceeding in Docket No. E-100, Sub 136 (the Sub 136 proceeding), the Commission initiated the 2014 avoided cost proceeding in advance of the filing of new proposed rates, stating that such rates would be required by a subsequent Commission order. The Commission scheduled an evidentiary hearing to consider changes to the method used to calculate avoided cost payments, particularly capacity payments, including, but not limited to, whether a 2.0 performance adjustment factor (PAF) for run-of-river hydroelectric facilities with no storage capability should be continued, whether avoided capacity payments are more appropriately calculated based on installed capacity rather than a per-kWh capacity payment, and whether the methods historically relied upon by the Commission to determine avoided cost capture the full avoided costs. Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, Inc. (DEP), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), Western Carolina University (WCU) and New River Light and Power Company (New River) were made parties to the proceeding. The Commission established May 30, 2014, as the deadline for interventions by interested persons; scheduled an evidentiary hearing for July 7, 2014, at 1:30 p.m.; and required that direct testimony and exhibits regarding the proper method to determine avoided costs payments, particularly capacity payments, be filed by April 17, 2014, responsive testimony be filed by May 30, 2014, and rebuttal testimony by June 20, 2014.

The following parties filed timely petitions to intervene that were granted by the Commission: the North Carolina Sustainable Energy Association (NCSEA); the Carolina Utility Customers Association, Inc.; the Carolina Industrial Customers for Fair Utility Rates I, II, and III (CIGFUR); the North Carolina Waste Awareness and Reduction Network (NC WARN); the Environmental Defense Fund (EDF); the Southern Alliance for Clean Energy (SACE); the North Carolina Hydro Group (NC Hydro Group); The Alliance for Solar Choice (TASC); the Public Works Commission of the City of Fayetteville; the North Carolina Chapter of the Sierra Club and the Natural Resources Defense Council (Sierra Club/NRDC); and Google, Inc.

On April 11, 2014, DEC, DEP, DNCP, NCSEA, CIGFUR, SACE and the Public Staff filed a joint motion requesting an eight-day extension to the deadline for the filing of direct testimony to April 25, 2014, an extension of the remaining due dates for filing testimony, and a rescheduling of the evidentiary hearing. By Order dated April 16, 2014, the Presiding Commissioner extended the deadline to file direct testimony and exhibits until April 25, 2014, but left the remainder of the procedural schedule and the hearing date as established in the Commission's Order dated February 25, 2014. WCU and New River filed Joint Comments and Proposed Rates on April 17, 2014.

On April 25, 2014, the parties filed the following direct testimony: DEC and DEP filed the testimony of Kendal C. Bowman, the testimony and exhibit of Glen A. Snider and the testimony and exhibit of Dr. Laurence J. Makovich; DNCP filed the testimony of Roger T. Williams with two appendices that were treated as exhibits and the testimony of Bruce E. Petrie with one appendix that was treated as an exhibit; EDF filed the testimony and exhibit of Diane Munns; NCSEA filed the testimony of Greg Ness, the testimony and exhibit of Michael Cohen, and the testimony and exhibits of R. Thomas Beach; TASC filed the testimony and exhibits of Anne Smart; SACE filed the testimony and exhibits of Karl R. Rábago; NC Hydro Group filed the testimony of Andrew C. Givens; NC WARN filed the testimony and exhibit of Nancy LaPlaca; and the Public Staff filed the testimony and exhibit of Dr. Laurence D. Kirsch and the testimony of Dr. Richard E. Brown. On May 20, 2014, NCSEA filed a motion for leave to file the direct testimony of K. Zoe G. Hanes adopting the direct testimony of Greg Ness which was granted by Order dated May 29, 2014.

On May 30, 2014, the parties filed the following supplemental direct and responsive testimony: DEC and DEP filed the testimony of Kendal C. Bowman, the testimony and exhibit of Glen A. Snider and the testimony of Dr. Laurence J. Makovich; DNCP filed the testimony of Roger T. Williams and Bruce E. Petrie, the testimony of James R. Bailey and Robert S. Wright, each with one appendix that was treated as an exhibit; NCSEA filed the testimony and exhibit of K. Zoë Gamble Hanes, the testimony of Michael Cohen and R. Thomas Beach, and the testimony and exhibit of Katie B. Rever; TASC filed the testimony and exhibits of J. Richard Hornby; SACE filed the testimony of Karl R. Rábago; Sierra Club/NRDC filed the testimony and exhibit of Dr. Alvaro E. Pereira; NC Hydro Group filed the testimony of Andrew C. Givens; NC WARN filed the testimony of Nancy LaPlaca with two attachments that were treated as exhibits; and the Public Staff filed confidential and public versions of the testimony of John Robert Hinton, the testimony of Kennie D. Ellis, and the responsive testimony of Dr. Richard E. Brown.

EDF filed the rebuttal testimony of Diane Munns on June 19, 2014. The other parties filed rebuttal testimony on June 20, 2014, as follows: DEC and DEP filed confidential and public versions of the testimony of Kendal C. Bowman, and the testimony of Glen A. Snider and Dr. Laurence J. Makovich; DNCP filed the testimony of Roger T. Williams and Bruce E. Petrie; NCSEA filed the testimony of K. Zoë Gamble Hanes, Jonathan M. Gross, and Angela Whitener Maier, and confidential and public versions of the testimony of R. Thomas Beach; TASC filed the testimony and exhibits of J. Richard Hornby; SACE filed the testimony and exhibits of Karl R. Rábago; and the Public Staff filed the testimony and exhibits of Kennie D. Ellis and the testimony of Dr. Richard E. Brown.

Also on June 20, 2014, the NC Hydro Group filed a motion for a one-day extension to file rebuttal testimony which was granted by Order issued June 23, 2014. On June 24, 2014, DEC and DEP filed the Stipulation of Settlement among DEC, DEP and the NC Hydro Group. This stipulation provided that, because of the state policy supporting small hydro facilities and the relatively small and finite amount of small hydro capacity in the state, the stipulating parties had agreed that DEC and DEP would continue to use the currently-approved 2.0 PAF to calculate the avoided cost rates for small hydro QFs of five MW or less and that small hydro QFs of five MW or less, otherwise eligible for power purchase contracts with DEC or DEP, would have the option of contract terms of five, ten, and 15 years, with the same hour options that small hydro QFs have at this time under DEC's Schedule PP-H and DEP's Schedule CSP-29. In addition, the stipulating parties further agreed that DEC and DEP would include and incorporate the foregoing in their proposed avoided cost rates and proposed standard terms and conditions pertaining to small hydro QFs filed at the Commission until December 31, 2020.

On June 24, 2014, DEC and DEP filed a corrected version of the rebuttal testimony of Kendal C. Bowman, stating that they had discovered that the confidential information in the testimony was disclosed without authorization and that the corrected testimony removed that information from the record. On July 3, 2014, Sierra Club/NRDC filed a motion to excuse their witness, Mr. Pereira, from appearing at the evidentiary hearing in this matter and to accept his pre-filed direct testimony into the record of the evidentiary hearing as if given orally at the hearing, indicating that all of the parties had agreed to stipulate to Mr. Pereira's testimony and waive their right to cross-examine him at the evidentiary hearing.

DNCP, by motion filed July 7, 2014, requested that the Commission excuse the appearance of its witnesses Bailey and Wright at the evidentiary hearing and allow the introduction of their prefiled responding testimony into the record at such hearing. In support of this motion, DNCP stated that it had reached agreement with the parties that had expressed an intention to cross-examine these witnesses at the hearing as follows: (1) counsel for DNCP and NCSEA stipulate to the following statements regarding the testimony of Mr. Bailey and Mr. Wright: (a) an important driver of DNCP's future transmission investments is the expected future load placed on DNCP's transmission system; (b) transmission is constructed to bring generation resources interconnected at transmission voltages reliably to loads, which can be served from both the transmission or distribution systems; and (c) DNCP has not yet completed or made public a study specific to its system of the impacts of solar generation on its transmission or distribution systems, although such a study is currently underway; and (2) counsel for DNCP and counsel for TASC and SACE agree to certain terms pursuant to which counsel for TASC and SACE could cross-examine DNCP's witnesses Williams and Petrie regarding the testimony and data responses prepared by Mr. Bailey and Mr. Wright. This motion was granted during the hearing on July 7, 2014. DNCP filed the verified response of its witness Bailey pursuant to the stipulation between DNCP and SACE as a late-filed exhibit on July 17, 2014.

On July 8, 2014, counsel for the NC Hydro Group filed a motion asking the Commission to excuse its witness Givens, stating that all parties had agreed to stipulate Mr. Givens' testimony into the record and to waive cross-examination. This motion was granted during the hearing on July 9, 2014.

Various other filings were made and orders issued that are not discussed in this Order, but are included in the record of this proceeding.

FINDINGS OF FACT

1. It is appropriate for DEC, DEP and DNCP to continue offering standard contracts to QF's under 5-MW_{AC}.

2. It is appropriate for DEC, DEP and DNCP to continue offering standard contracts with a maximum term of 15 years.

3. DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity. The standard levelized rate options of ten or more years should include a condition making contracts under those options renewable for subsequent terms at the option of the utility on substantially the same terms and provisions and at a rate either

(1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration.

4. The standard five-year levelized rate option should be offered to all other QFs contracting to sell three MW or less capacity.

5. It is inappropriate for DEC, DEP and DNCP when negotiating contracts with QFs that are not eligible for standard contracts to employ methods found by the Commission to be inappropriate in the application of the peaker method when calculating standard contract rates.

6. The peaker method, as historically relied upon by the Commission to determine avoided cost, has captured the utilities' avoided costs generally and should be retained.

7. It is inappropriate to approve DNCP's proposed "Net Peaker" method at this time.

8. It is inappropriate in this docket to approve DEC and DEP's proposal to cap the production cost savings in each hour at the assumed production cost of the most efficient CT.

9. It is inappropriate in this docket, when employing the peaker method, to require the inclusion of zeroes for the early years when calculating avoided capacity rates.

10. Integration of solar resources into a utility's generation mix, depending in part upon their location, may result in costs and/or benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculations. Thus, it is appropriate for the costs and benefits attributed to solar integration as such integration becomes more pervasive to be more fully evaluated in detailed integration studies.

11. It is appropriate to consider hedging and environmental costs outside the scope of such a solar integration study.

12. Renewable generation provides fuel price hedging benefits because a utility's purchase of energy from a QF reduces the amount of fuel the utility otherwise would need to purchase.

13. Hedging benefits should be valued only over the hedging terms (time period) actually used by DEC, DEP and DNCP. The utilities should calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding.

14. The costs of carbon emissions control are not sufficiently certain to be included in avoided costs at this time. If in the future carbon costs become known and verifiable, it may be appropriate for those costs to be included at that time.

15. The generation expansion plans used in avoided cost production cost models should be based on IRP expansion plans that take into account only known and quantifiable costs.

16. It is appropriate to include economies of scale in the calculation of the installed cost of a CT. When constructing CT units, utilities are likely to construct up to four units at the same site.

17. It is inappropriate to include economies of scope in the calculation of the installed cost of a CT. When constructing CT units, utilities are unlikely to construct multiple units at the same time.

18. It is appropriate to include the cost of land for a greenfield site in the calculation of the installed cost of a CT.

19. It is appropriate to include transmission interconnection costs, but not network upgrade costs, plus a reasonable contingency adder for a hypothetical plant in relatively early stages of planning and a reasonable estimate of useful life of a CT in the calculation of the installed cost of a CT.

20. It is appropriate to calculate avoided capacity payments based on a per-kWh capacity payment, rather than on an installed cost per kW basis.

21. DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the settlement agreements entered into between and among DEC, DEP, DNCP, the Renewable Energy Group and the Public Staff in the Sub 136 proceeding.

22. DEC, DEP and DNCP should continue to offer an Option A set of avoided capacity rates. Both proposed Option A and Option B capacity rates should be included in the utilities proposed rate filing in phase two of this proceeding.

23. The availability of a CT is not determinative for purposes of calculating a Performance Adjustment Factor (PAF) because the fixed costs of a peaking unit in the peaker method employed by the Commission are a proxy for the capacity-related portion of the fixed costs of any avoided generating unit.

24. The 1.2 PAF should be utilized by DEC, DEP and DNCP (for its Schedule 19-FP) in their respective avoided cost calculations for all QFs other than run-of-the-river hydroelectric facilities with no storage capability.

25. It is inconsistent with the method employed in the calculation of avoided costs to utilize a 2.0 PAF for run-of–the-river hydro. As the Commission has historically used this calculation it is appropriate to discontinue the use of the 2.0 PAF for run-of-river hydroelectric facilities with no storage capability and no other source of generation in accordance with the stipulation filed by DEC, DEP and the NC Hydro Group.

26. It is premature for DEC, DEP and DNCP to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation

of their avoided cost rates. The Commission is aware of several ongoing studies and future developments that may further clarify theses costs and benefits for consideration in future proceedings.

27. It is appropriate for the utilities to continue to follow their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.

28. It is inappropriate to calculate off-peak avoided energy rates for solar QFs at this time.

29. DNCP's proposal to provide a simple form to be completed by a QF seeking to sell its output to DNCP has merit; the details as to its implementation should be addressed in the next phase of this proceeding.

30. It is premature to retract the 30-month timeframe for completion of construction, given that it was approved shortly before the Commission issued the order initiating this proceeding. This timeframe is the best means of resolving a number of competing issues that were raised in the Sub 136 proceeding.

31. It is appropriate that the currently approved avoided cost rates and tariffs remain available until the date the utilities file new proposed avoided cost rates in compliance with this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witnesses Bowman and Snider; the testimony of DNCP witnesses Williams and Petrie; the testimony of NCSEA witnesses Hanes, Cohen, Rever, Meier, Gross and Beach; the testimony of SACE witness Rábago; the testimony of TASC witness Hornby; and the testimony of Public Staff witness Hinton.

DEC/DEP witness Bowman testified that DEC and DEP apply the peaker method to establish a standard avoided cost rate structure that is applied to all renewable QFs contracting to sell five MW or less and to all nonrenewable QFs of three MW or less. She noted that this definition of QFs eligible for the standard terms and rates covers a wide range of generation types and sizes. She testified that generally the peaker method is a reasonable approach to assessing a utility's avoided cost, but that using it to establish a single, standard rate cannot reasonably account for all of the differences between the varieties of QFs currently eligible for the standard rate. Similarly, a single set of "standard" terms cannot address issues that may be specific to particular types of QFs or to specific QF projects. Conversely, in a bilateral negotiation, the specific characteristics of a particular QF can be taken into consideration. Witness Bowman testified that the Commission has long acknowledged this in describing the types of factors that it expected such negotiations should encompass. Accordingly, bilateral negotiations are better suited to accurately measure the avoided cost associated with a particular QF than are standard terms and rates.

Witness Bowman testified that prior to 1985, standard avoided cost tariffs from DEC and DEP were available to all QFs of up to 80 MWs. In Docket No. E-100, Sub 41A, the Commission established a five MW eligibility limit for the standard tariffs. She noted that the small power production industry was in a nascent stage at that time, and, therefore, the Commission established eligibility criteria that ensured that smaller project developers that may not have the resources or expertise to negotiate with a utility, still had access to the standard terms and conditions. Witness Bowman stated that the industry has changed considerably in the past 30 years. The underlying public policy objectives are evolving and the technologies being utilized have changed. In today's environment, developers of even smaller projects tend to be well-experienced and sophisticated entities. Currently, in North Carolina, developers of QFs are routinely planning and developing projects both inside and outside the standard tariff parameters. As a result, Witness Bowman concluded that the prior justification for the five MW threshold simply no longer exists.

In responsive testimony, witness Bowman testified that public policy does not support extending eligibility to ten MW or the contract term to 20 years as proposed by some intervening parties. She further testified that, as witness Snider explained, the biennial process for establishing avoided cost rates results in application of the same rates to QFs even if they are put in service years apart. The effect of the imprecision inherent in that process would be mitigated by limiting the availability of those rates to smaller projects. Conversely, she testified that raising the eligibility cap exacerbates the problem by making more projects eligible for the standard avoided cost rates. She further testified that, given the cost and complexity of developing such facilities, any developer that intends to construct a QF facility that is five MW or larger will undoubtedly be more sophisticated and well-informed. Moreover, the transaction costs associated with bilateral negotiations would be small compared to the overall cost of the QF project. Thus, the policy rationale for requiring standard terms and conditions for certain QFs is inapplicable to the large-scale projects to which some parties wish to apply it.

With respect to G.S. 62-133.8(d), which provides that the terms of any contract entered into between an electric power supplier and a new solar electric facility be of sufficient length to stimulate development of solar energy, witness Bowman agreed on cross-examination that when this was enacted into law, the standard contract options were in place and available. As to the stipulation among DEC, DEP and the North Carolina Hydro Group, she testified that it provided that the five, ten, and 15-year standard rates and contracts would remain available run-of-the-river hydro QFs. Witness Bowman also stated that page 39 of the Annual Report on Corporate Governance filed by Duke Energy on March 31, 2014, indicated that Duke Energy Renewables, a developer of QFs in non-Duke service territories, mostly has contracts with terms that approximate the estimated useful life of the underlying generation project. She also agreed that solar generally has a warrantied life of 25 years.

DEC/DEP witness Snider testified that the NC REPS compliance requirements, the impact of state and federal tax incentives, and declining solar prices have resulted in a large solar QF development effort in North Carolina. Approximately 1,000 MWs of potential solar projects currently in DEC’s and DEP’s queues fall in the 100 kW to five MW range. Under the current fixed tariff structure, all 1,000 MWs receive the same price signal which, according to witness Snider, overstates the cumulative value created if all 1,000 MWs were to come to fruition. He further testified that QF contracts represent a long-term fixed price obligation on behalf of DEC and DEP’s customers. QFs receive tariff prices that are based largely on forecasts of future fuel prices rather than actual fuel prices. Witness Snider argued that limiting the contract term to a maximum of ten years does not limit the QF's ability to continue to receive income over the life of the asset. He stated that at the expiration of the original contract, the QF has the right under PURPA to enter into another contract with the utility at the then prevailing avoided cost rates assuming (a) the requirements of Section 210 of PURPA are still in place and (b) the QF is still financially and operationally viable. This would better align the QF payment obligation borne by customers with the avoided cost value the QF actually creates.

DNCP witness Williams testified that DNCP does not believe the current size limits are appropriate and that standard rates should be limited to projects 100 kW or less. He testified that PURPA was intended to encourage alternative generation by developing standard terms for "small" projects. Witness Williams stated that this size limit needs to change because QF development activities in DNCP's service territory have changed dramatically in the past year. In most instances, these development projects are not "mom-and-pop" operations; they are owned by sophisticated companies backed by sophisticated financing, often with broad portfolios of renewable generation, that do not require the simplicity and benefits of a standard tariff. He stated that nearly all of the smaller projects being proposed for DNCP's service area are owned by companies that are also pursuing larger projects, or multiple small projects, totaling 100 MW or more in North Carolina. Because solar is easily scalable, companies pursuing very large scale solar development, representing hundreds of millions in investment dollars, are simply building a multitude of sites in exactly five MW increments to avail themselves of the standard contract benefits. According to witness Williams, facilities entitled to the benefits of Schedule 19 are no longer "generally of limited number and size" as previously noted by the Commission in earlier orders.

Witness Williams testified that DNCP believes that levelized rates should only be applied to QFs that qualify for standard contracts (which would be those at 100 kW or less under DNCP's proposal and for a term of ten years or less. A threshold of 100 kW or less would provide better protection for DNCP's customers with respect to risk associated with non-performance, and ultimately would better align payments to QFs with the Company's actual avoided cost. He testified that DNCP believes that the maximum contract duration for levelized rates should be ten years instead of the currently available 15-year term. If a QF desires 15-year fixed rates (or any term greater than ten years), it should be on a non-levelized basis because of the discrepancy between the payment to the QF and the utility's avoided cost in any particular year that is created by levelization.

In his responsive testimony, witness Williams testified that extending the maximum term of contracts under PURPA to 20 years is unnecessary and adverse to the utility and its customers because of the uncertainty of long-term avoided cost projections. Given this degree of uncertainty, DNCP believes that such long-term projects are therefore not an appropriate basis for fixing rates in a contract. Moreover, with no credit security or performance assurances in a Schedule 19 contract, the Company's exposure to counterparty, equipment performance and other risks are substantially greater for long-term contracts. On cross examination DNCP witnesses Williams and Petrie acknowledged that in negotiations with facilities larger than five MW, DNCP has included newly proposed methods, such as the net-peaker and no capacity in the first three years, which are addressed in this Order.

NCSEA witness Hanes testified that when FLS Energy, Inc. (FLS), first began developing utility-scale solar QFs in North Carolina in 2012, the company developed smaller facilities, primarily one MW or less. However, over time, the size of the QF around which its business model revolves has grown, primarily because of decreasing revenue streams – resulting from decreasing rates and decreasing prices paid for RECs – and the need to spread certain fixed costs over increased generation to improve cost effectiveness. She further testified that FLS's experience in negotiating REC agreements and her observation of other developers attempting to negotiate PPAs is that such negotiations can be protracted, which seems an inefficient use of utility time and resources, QF developer time and resources, often Public Staff time and resources, and, on occasion, Commission time and resources. Additionally, such negotiations add significant additional transactional costs to QF project development. Witness Hanes stated that this, combined with the need for certainty by investors and lenders, has influenced FLS's primary strategy of limiting QF development to less than five MW. In the context of QFs greater than five MW, to her knowledge DEC has entered into PPAs with only six QFs, of which two are solar (or three if Apple's projects are treated as separate contracts). She further testified that since 2010, DEP has entered into PPAs with eight QFs greater than five MW, none of which are solar.

Witness Hanes testified that long-term contracts or PPAs enable investors to calculate return on investment with certainty and instill confidence that the borrower will be in a position to repay any loan extended. With increased price certainty for a project, investors typically require a lower return, which, in turn, reduces the cost of financing. She concluded that the inability of a project's revenue stream to cover its cost of capital results in the project not being financeable. As a result, she testified that, in the interests of reducing the cost to finance facilities and therefore encouraging the development of QFs, the Commission should direct the utilities to offer a 20-year terms for the standard offer. She noted that a 20-year term would be consistent with the industry standard term for a PPA that even the unregulated divisions at Duke and Dominion have themselves secured, the details for which were shown in Hanes Exhibit 1, and NCSEA Bowman Cross-Examination Exhibit No. 1. Witness Hanes testified that no matter how sophisticated QF developers have become, the disparity in size between the three investor-owned utilities in North Carolina and even large solar developers is still enormous. A QF can sell the product only to one buyer, and this buyer may not really want the product. Under this scenario, the developer has minimal leverage and bargaining power when it comes to negotiating with a utility.

NCSEA witness Cohen testified that Strata Solar's (Strata) experience has been similar and that long-term contracts or PPAs are necessary for projects to be developed. He stated that he does not believe that a 20-year term disrupts this balance and, furthermore, that a 20-year term is necessary to encourage QF development in the current environment. The service life of the solar equipment installed by Strata is expected to be a minimum of 20 years. Thus, a 20-year PPA will better match the avoided cost revenue stream to the useful life of the equipment. Witness Cohen stated that the revenue QFs earn from the sale of electricity and RECs has declined dramatically over the past four years, putting the solar industry in North Carolina under considerable cost pressure. In 2010, the price of a solar REC was around $200 per MWh; today, that price is close to five dollars per MWh. More recently, the standard rates for the output generated at Strata's newer farms were reduced by more than 20 percent as result of the 2012 biennial proceeding. Looking forward, witness Cohen stated that the North Carolina tax credit for investing in renewable energy property, G.S. 105-129.16A, is scheduled to expire at the end of 2015, and the federal business energy investment tax credit will be reduced at the end of 2016. For all of these reasons, he stated that reducing the cost to develop the QF, such as through a 20-year PPA, increases the possibility that a project will be cost effective and will actually be developed, particularly in an environment of decreasing revenue streams and increasing difficulty in securing certain types of financing.

With respect to the process of negotiating a PPA with the utilities, witness Cohen testified that the elimination of the standard contract for all but the smallest QFs will dramatically increase the number of QFs negotiating PPAs with the utilities. He stated that the negotiation process already is protracted. PPA negotiations for Strata projects have been on-going for many months, and, to date, many are unsuccessful. He further testified that he is aware of other developers that have had similar experience in attempting to negotiate a PPA. Such a protracted process is an unnecessary waste of time and resources for everyone involved. He asserted that moving to a ten MW upper limit for the standard contract will further streamline the process and mitigate the difficulties QFs currently face as they attempt to negotiate PPAs. At a minimum, he stated that the current five MW size should not be reduced.

NCSEA witness Rever testified that DEC/DEP witness Bowman and DNCP witness Williams stated that solar developers are more experienced and sophisticated, routinely planning and developing projects both inside and outside the standard tariff parameters, but that they ignored the fact that the industry is not actually able routinely to develop projects outside the tariff parameters. She stated that the limited number of larger QFs in operation is telling. She further testified that the utilities' current track record with respect to negotiated PPAs calls into question one of their central premises for their proposals – that QFs larger than 100 kW would receive full avoided cost rates through bilateral negotiations with the purchasing utility. Witness Rever stated that it seems highly unlikely that, if the utilities' proposals were approved, more PPAs would be executed at rates and terms agreed upon "bilaterally."

Witness Rever further testified that the utilities' proposal to reduce the eligibility limit for the standard offer PPA would essentially "slow-track" PPA negotiations for QFs larger than 100 kW at the same time that the FERC has evidenced its intent that larger solar projects be fast tracked for purposes of interconnection agreements. She noted that FERC states in its November, 2013 Order No. 792, the package of reforms adopted in its Final Rule will reduce the time and cost to process small (up to 20 MW) generator interconnection requests, maintain reliability, increase energy supply, and remove barriers to the development of new energy resources. She further testified that the utilities' recommendation to reduce the eligibility limit of the standard offer PPA would work to thwart the FERC's desire to remove barriers to development. Finally, she testified that, in the interest of (1) encouraging the development of solar QFs; (2) making the most efficient use of resources; (3) keeping transaction costs to a minimum, and (4) following the FERC's goal of reducing transaction costs and decreasing the time to operation, the Commission should not reduce the eligibility cap for standard offer PPAs.

NCSEA witness Beach testified that the reduction in the standard contract size from five MW to 100 kW as requested by the utilities is likely to significantly slow, if not halt, QF development. With respect to DEC/DEP witness Bowman's reference to the Idaho Commission's decision to allow Idaho Power to reduce its standard contract size from 10 MW to 100 kW in response to what she characterizes as a "tremendous surge" in new and proposed wind QFs in that state, he testified that the practical result of this order has been to halt all further wind development in Idaho, even though wind QFs remain entitled to full avoided cost contracts through negotiations with the Idaho utilities. This experience, as well as the history of QF development where standard offer contracts for QFs over 100 kW have been suspended, he contended, calls into serious question witness Bowman's assertion that, if the utilities are allowed to negotiate rates for QF projects larger than 100 kW, "[t]he utilities will still be required to purchase the output of larger QFs, and the avoided cost requirements would still apply."

SACE witness Rábago testified that DEC/DEP witness Bowman's concern that raising the cap on standard offer contracts to ten MW will result in too much QF development is not a valid concern. He stated that Congress made a policy determination to encourage renewable generation when it enacted PURPA, a fact that utility witnesses persistently have ignored in this proceeding. He asserted that North Carolina ratepayers benefit from increased reliance on cost effective, clean electricity generation, even if those resources are not built by the utility companies. With respect to the length of the standard contract, witness Rábago testified that it is a best practice to set contract length to correspond to the life of solar assets. One entity that demonstrates this best practice is Duke's unregulated subsidiary, Duke Energy Renewables, which has entered into 20-year (and longer) solar contracts as a matter of course, citing Exhibit 1 to the responsive testimony of NCSEA witness Hanes.

Public Staff witness Hinton testified that the Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by the FERC regulations and has previously rejected efforts by the utilities to lower the five MW threshold for renewable QFs (e.g. Docket No. E-100, Subs 100, 96, 87, and 79), finding this threshold to represent the appropriate balance. He testified that the Public Staff shares this perspective, and that, in addition to ensuring compliance with PURPA, the Public Staff believes that setting the standard threshold at a level that allows QFs to receive the benefit of reduced transaction costs and appropriate economies of scale provides ratepayers with the assurance that the utilities' resource needs are being met by the lowest cost options that may be available. He further testified that the Commission has concluded in past biennial proceedings that QFs not eligible for the standard long-term levelized rates have the option of "entering into contracts and rates "derived by free and open negotiations with the utility." The Public Staff's investigation of this issue indicates that QFs have had relatively limited success in obtaining negotiated contracts with the utilities in North Carolina. Witness Hinton stated that DEP has yet to execute a single negotiated PPA with a solar QF, DEC has negotiated two such PPAs and DNCP has recently entered into two PPAs with solar QFs with a capacity greater than five MW, one of which the Public Staff was asked informally to resolve disputes that arose; the other is with a subsidiary of Duke Energy Renewables.

Witness Hinton also stated that the Public Staff has been involved to varying degrees in attempts to resolve dispute between utilities and QFs that have arisen during PPA negotiations. Based on the Public Staff's experience and the small number of contracts that have actually been executed, it appears that the process of negotiating PPA contracts has not been very successful. Additionally, responses to Public Staff data requests to the utilities and NCSEA indicate that it may take well in excess of 12 months for the utility to complete an interconnection study for a project with generation capacity greater than five MW. Witness Hinton noted that while QFs maintain the right to petition for arbitration before the Commission, this process is also time consuming and adds significant transaction costs. At the time the testimony was filed, four QFs had filed petitions for arbitration with the Commission. The two arbitrations that were completed were long and contentious proceedings.

Witness Hinton testified that the Commission has previously concluded that the current long-term contract options serve important statewide policy interests while limiting the utilities' exposure to overpayments. He further testified that Section 292.304(d)(2) of the FERC's regulations provides that a QF may choose to sell energy or capacity pursuant to a legally enforceable obligation (LEO) for delivery "over a specified term." As the Commission has recognized in recent orders, the FERC has ruled that QFs have a right to fixed long-term avoided cost contracts or other LEOs with rates determined at the time the obligation is incurred.

According to witness Hinton, the Public Staff finds merit in the arguments raised by both sides with respect to the length of avoided cost contracts. Witness Hinton further testified that, in past proceedings, the Public Staff has maintained that fixed long-term rates needed to be at least 15 years in length in order to ensure that QFs could secure reasonable financing and the Public Staff believes that North Carolina's long-standing policy has been beneficial to QFs. He further stated that the Public Staff has reviewed policies in other states and found some with shorter terms and others with longer terms, but no clear standard term. Witness Hinton noted that a rate for a ten-year term or a variable rate would add an element of risk, and the banking industry would want additional equity in the capital structure relative to the current fixed 15-year terms.

With regard to the proposal by NCSEA's witnesses to extend the contract terms to 20 years, witness Hinton testified that the Public Staff believes that the increased risk to ratepayers that avoided costs could substantially change over that longer period outweighs the financing benefits. He stated that, given the number of currently operating facilities and the number of solar projects in development, it appears that North Carolina's standard 15-year contract has been accepted by the financing community. With respect to DNCP's concern about levelized rates, witness Hinton testified that witness Williams' position seems to be based on the increased possibility that a QF's output will decrease over the long term based on numerous factors, including degraded performance, financial failure, weather, fuel supply, or other risks that could lead to overpayment. This may be a valid concern with regard to QFs that must rely on fuel contracts, the viability of a steam host, or some other external factor that adds risk to future viability. However, according to witness Hinton, a solar generating facility has fairly predictable capital costs, production profiles, and other characteristics, such as zero fuel costs, that allay many of the concerns raised by DNCP witness Williams, and, thus, the Public Staff does not recommend reducing the availability of levelized rates.

In rebuttal testimony DEC/DEP witnesses noted that the same avoided cost rates may be applicable to QFs even if they are put in service years apart. During that lengthy interval, factors affecting the purchasing utility's avoided costs, such as fuel costs, environmental regulations, and capacity needs, can change dramatically. According to these witnesses, negotiated contracts eliminate this problem by using more currently calculated avoided cost rates for each contract, which better serve the policy goals of PURPA. In support of requiring most QFs to negotiate contracts, witness Bowman noted that, even before the initiation of this docket, DEC and DEP have been taking steps to further streamline the QF PPA negotiation process. Recognizing the continued growth in proposed QF projects, they undertook to develop a standardized form PPA to be used as the basis for all negotiated QF contracts. Moreover, she stated that they recognize that different types of QFs may require different commercial terms in their PPAs and that they have incorporated that concept into their standard form. Witness Bowman emphasized that the main objective of their proposal is to apply more current avoided cost data to a greater percentage of new QFs.

NCSEA witness Hanes, in rebuttal testimony, argued that the development of QFs is a very capital intensive process and that the negotiations between the developer and utility come after the developer has sunk considerable capital into a project. Witness Hanes stated that when a utility is slow to negotiate or proffers terms that are objectionable, the developer does not have the option of finding another utility with which to work. She noted that, if a deal cannot be reached, the expenditures made for that site are lost, which puts the developer, no matter its size or level of sophistication, in a very weak negotiating position. Witness Hanes also noted that the timing of the negotiating process has significant implications for every project; because tax equity is an important source of financing for solar QFs and timing issues related to the use of tax credits on an annual basis, a QF project must be put into service by year end. Any possible delay has the potential to jeopardize project finance. The utility retains significant control over the timing of the negotiation process.

Witness Cohen testified that he is aware of PPA negotiations for Strata projects that have been on-going for many months. He testified that he also is aware of efforts by Strata to negotiate PPAs that were abandoned as futile with the project subsequently downsized to five MW in an effort not to lose the money already expended on the project. Because of protracted negotiations on another project, Strata downsized its Mt. Olive project in order to avoid going through the negotiation process again. He testified that Strata has not filed an arbitration proceeding because it can ill afford to alienate the utilities, stating that "they are the only game in town." However, according to witness Cohen, arbitration petitions will likely become a necessary fact of life if the proposal to reduce eligibility for the standard QF contract were to be adopted in this proceeding. In response to a question from a commissioner, witness Cohen testified that Strata has accepted terms it feels are unjust simply to avoid arbitration, stating that the time element is part of why it has done so.

NCSEA rebuttal witness Gross, a certified public accountant, testified that in his experience most commercial banks will not lend to QFs in North Carolina as these banks consider QFs to be nonstandard and higher risk, at least compared to more conventional lending projects. According to witness Gross, only a handful of smaller banks and lending institutions that specialize in lending to projects perceived to have higher risk or complexity are willing to provide permanent debt for QFs. He further testified that the terms of the PPA have been a significant factor in every case of which he is aware in North Carolina for both debt and equity investment underwriting. A lender typically will not provide for a loan term that is longer than the PPA term. Debt and equity investors require long-term PPAs of 15 to 20 years. With respect to the utilities' concerns about nonperformance, he testified that they are unwarranted. Default under the financing arrangements could result in such things as the change of control rights of equity investors being triggered and of the owners being required to pay liquidated damages under loan documents. In addition, he testified that the generating facility is pledged as security for the debt financing and typically the developer is also required to provide a corporate and/or personal guaranty and/or to pledge assets in addition to the generating facility. Witness Gross further stated that, with only a ten-year term, many projects would not be able to secure financing. Finally, he testified that the availability of a 15-year term is a very significant factor, and, even then, in some cases the PPA will not be of sufficient length to allow adequate financing to cover project costs. Therefore, the Commission should consider increasing the 15-year term in light of the changing circumstances, rather than decreasing it.

NCSEA witness Maier's rebuttal testimony addressed the swine waste-to-energy set aside in the REPS law. She testified that the Pork Council believes the utilities' proposals will make it more difficult for swine waste-fueled QFs to be developed, become operational, and generate the necessary swine waste RECs for compliance to occur. She stated that each of the utilities' proposals will inject uncertainty in project development and has the potential to reduce the return on investment. She testified that, in the interest of (1) encouraging the development of swine waste-fueled QFs; (2) making the most efficient use of resources; and (3) keeping transaction costs to a minimum, the Pork Council believes the Commission should reject the utilities' proposals to reduce the standard offer eligibility threshold to 100 kW and reject their proposals to eliminate the availability of a 15-year fixed term financing option under the standard offer.

DISCUSSION AND CONCLUSIONS

Whether the Commission should require the electric utilities to offer long-term levelized rates to a QF as standard rate options has been an issue in prior avoided cost proceedings, including Docket No. E-100, Subs 79, 81 and 87, in which at least two of DEP, DEC, and DNCP in each proceeding proposed eliminating the ten- and 15-year levelized rate options from the standard rates available to QFs. The utilities contended that these rates are based on long-term projections of costs that are inherently unreliable. They further noted that ten and 15-year levelized rates are not specifically required by either state or federal law. Despite the increasingly competitive wholesale markets that had developed during the 1990's, the Commission rejected the utilities' proposals to eliminate the standard rate options and long-term contract options in all three proceedings. In the 2002 proceeding, in Docket No. E-100, Sub 96, DEC again proposed eliminating ten and 15-year capacity and energy rates, while DNCP proposed eliminating the two-year capacity rate and the ten and 15-year energy and capacity rates. Similarly, in the Sub 100 proceeding in 2004, DEC proposed to limit the availability of ten and 15-year levelized rate options to new projects. DEC contended that perpetually offering standard long-term rate options to QFs renewing contracts beyond their initial terms is unwarranted. It proposed limiting renewing projects to five-year levelized rates. The Commission again rejected these proposals.

While the Commission initiated this docket to investigate the need to alter avoided costs determinations, the evidence presented by the buyers and sellers of QF power fail to justify altering the Commission's earlier decisions on term length and related provisions. As discussed earlier, a QF's legal right to long-term fixed rates under Section 210 of PURPA is well established as a result of the FERC's J.D. Wind Orders. The FERC has made clear that its intention in Order No. 69 was to enable a QF to establish a fixed contract price for its energy and capacity at the outset of its obligation because fixed prices were necessary for an investor to be able to estimate with reasonable certainty the expected return on a potential investment, and therefore its financial feasibility, before beginning the construction of a facility. In her responses to cross-examination questions about various Duke Energy Renewables projects, DEC/DEP witness Bowman acknowledged the foregoing by stating that PURPA does not require the best financing, just the ability to secure it. In addition to the foregoing, G.S. 62-133.8(d) provides that the terms of any contract entered into between an electric power supplier and a new solar electric facility "… shall be of sufficient length to stimulate development of solar energy."

In support of their positions with respect to reducing eligibility for standard contracts to 100 kW and eliminating 15-year contracts, DEC and DEP's testimony in this proceeding suggests that the public policy objectives underlying Section 210 of PURPA have outlived the circumstances that led to its enactment or at a minimum evolved beyond being justification for long-term standard contracts and rates for QFs five MW and under. As addressed earlier in this Order, Congress' retention of Section 210 of PURPA in 2005 and the FERC's establishment of a rebuttable presumption that QFs 20 MWs and smaller do not have access to nondiscriminatory wholesale markets, even in areas with markets operated by RTOs, suggest an opposite conclusion. While the utilities testify about solar developers being well-experienced and sophisticated entities that are routinely planning and developing projects both inside and outside the standard tariff parameters, the solar developers' testimony demonstrates that negotiating PPAs for projects that fall outside the standard tariff is a very challenging proposition. While much of this challenge results from interconnection issues, the evidence in the record shows that very few negotiated contracts with QFs larger than five MW have been executed, despite the existence of a large amount of QF development (i.e., CPCNs granted and interconnection requests made).

While witness Snider's emphases that QF contracts represent long-term fixed price obligations on behalf of DEC's and DEP's customers based largely on forecasts of future fuel prices, the Commission recognizes that a utility's commitment to build a plant represents a similar type of long-term fixed obligation for the utility's customers, largely based upon forecasts of future prices. In many respects the utilities own self-build options are based upon similar "uncertain" forecasts. The FERC's order implementing Section 210 of PURPA states that the goal is to make ratepayers indifferent between a utility self-build option or alternative purchase and a purchase from a QF. Indeed, the FERC concluded that ratepayers benefit anyway because of the resulting reduced use of fossil fuels, the addition of smaller increments of capacity, and the resulting diversity of power supply.

As to DNCP's concern about levelized rates, the Commission concludes that experience has shown that there is a limited risk of nonperformance. In addition, the testimony offered by the solar developers as to the restrictions and limitations in their financing offers a measure of assurance that a solar QF's output will not decrease over the long term. The fact that solar QFs do not have to rely on fuel contracts, the viability of a steam host or some other external factor also weighs in favor of allowing levelized rates to continue. A solar generating facility has fairly predictable capital costs, production profiles, and other characteristics, such as zero fuel costs, that allay many of the concerns raised by DNCP witness Williams.

The Commission acknowledges that the negotiation of PPAs is a complicated process and that the interconnection of QFs to the grid is a highly technical process that contains many moving parts to ensure that a QF is reliably and safely interconnected. The Commission notes the evidence that an interconnection study for a project larger than five MW can take well in excess of 12 months for the utility to complete. These delays caused by both negotiating a PPA and the interconnection process place QFs in a difficult position with regard to their ability to secure project financing in a timely fashion and raises transaction costs. The Commission determines that overestimating avoided costs creates costs ultimately borne by ratepayers and underestimating avoided costs creates risks for the QF developers. Failure to calculate accurately a utility's avoided cost means ratepayers will pay for the additional energy and capacity whether the utility builds the plant and places it in rate base or the utility pays QFs avoided cost rates. The Commission concludes that establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 210 of PURPA should leave the utilities' ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources.

Several parties to this proceeding presented evidence regarding the difficulty in obtaining a negotiated PPA. The Commission agrees with DEC/DEP witness Bowman that in a bilateral negotiation the specific characteristics of a particular QF can be taken into consideration. In addition a bilateral negotiation can utilize the most up-to-date data. However, the method by which avoided costs are calculated should, to the extent possible, remain consistent in both standard and negotiated contracts. If a method is not applicable to calculating the avoided costs of a QF smaller than five MW, the fact that a QF is greater than five MW does not validate such a method. In an effort to ease the negotiation process and avoid unnecessary and protracted proceedings, the Commission determines not to authorize DEC, DEP and DNCP when negotiating contracts with QFs that are not eligible for standard contracts to employ methods found by the Commission to be inappropriate in the application of the peaker method when calculating standard contract rates.

The Commission must also balance the federal and North Carolina public policy requirement that QFs be encouraged against the risks and burdens that long-term contracts place on customers. Increasing the maximum cap for eligibility for the standard contract to ten MW and extending the maximum standard contract term to 20 years may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers. Based upon the foregoing, the Commission determines not to approve the proposals to increase the size limit to ten MW and extend the maximum term length to 20 years.

In balancing the costs, benefits and risks to all parties and customers, the Commission recognizes that regulatory continuity and certainty play a role in the development and implementation of sound utility regulatory policy. The record shows widespread QF development under the existing framework. While the parties have proposed various changes based on competing business models, there is insufficient evidence that the current framework fails to comply with the requirements of PURPA or otherwise disadvantages QFs. Absent such evidence, the Commission determines it inadvisable in this docket to introduce regulatory uncertainty by changing the existing framework.

Based on the evidence in the record, the Commission finds it is appropriate to retain the five MW threshold and 15-year maximum term length. The Commission concludes that DEC, DEP and DNCP should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by SPPs contracting to sell five MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills or hog waste, solar, wind, and non-animal forms of biomass contracting to sell five MW or less capacity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-9

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witnesses Bowman and Snider, the testimony of DNCP witnesses Williams and Petrie, the testimony of NCSEA witness Beach, the testimony of SACE witness Rábago, the testimony of TASC witness Hornby and the testimony of Public Staff witnesses Kirsch and Hinton.

DEC and DEP have used the peaker method to develop their avoided costs in most of the past avoided cost proceedings; DNCP previously used the Differential Revenue Requirement (DRR) method. In the Sub 136 proceeding, in response to the Commission's directive that DNCP file proposed fixed long-term, levelized avoided rates for QFs entitled to standard contracts, DNCP employed the peaker method to calculate the avoided cost rates in its proposed Schedule 19-FP.

In the Sub 136 proceeding, several parties raised issues related to the appropriate method, which can be summarized as follows: (1) the accuracy of the various ways to describe and implement the peaker method and whether other potential methods for determining avoided costs should be used; (2) various changes and refinements to the peaker method, generally including ways in which its implementation can be corrected or improved, specifically including (a) DNCP's proposed use of the net peaker method, and (b) DEC and DEP's proposed cap on avoided energy cost saving at the cost of the avoided CT; (3) the appropriateness of replacing the annual installed cost of a CT with zeroes in the first few years of the period for which rates are being calculated; (4) the relevance of VOS studies and what is and is not appropriately included in avoided cost rates determined pursuant to Section 210 of PURPA; and (5) whether or not technology-specific QF rates, particularly for solar QFs, should be developed. The first three issues will be discussed separately in this section. The VOS studies and technology-specific rates will be discussed in the section immediately following this section.

DEC/DEP witness Bowman testified that using the peaker method to establish a single, standard rate cannot reasonably account for all of the differences between the varieties of QFs currently eligible for the standard rate. While not recommending that the Commission use a different method, she testified that DEC and DEP have concerns that the current method for calculating avoided capacity and energy costs under the peaker method does not accurately reflect the value of the QFs' capacity and energy to their customers. With respect to avoided capacity rates, she recommended that the Commission establish the parameters of the key inputs used to calculate the installed cost of a CT and to calculate the capacity credits in the standard tariffs in a manner that takes into account the utility's relative need for generating capacity. With respect to energy costs, she recommended that the Commission recognize specific, measurable integration costs associated with intermittent solar generation and adjust for lost production cost benefits associated with the units being avoided through the purchase of QF power. Witness Bowman asserted that the intent of PURPA was not to force utilities to pay for capacity that they do not otherwise need, and that both Order No. 69 and subsequent FERC decisions have reinforced this point. She noted that North Carolina law also contemplates not paying for unneeded QF generation in that "a determination of the avoided energy costs to the utility shall include ... the expected costs of the additional or existing generating capacity which could be displaced ..." G.S. 62-156(b)(2). She testified that DEC and DEP's recommendation seeks to effectuate this concept in allowing avoided capacity credits provided to QFs to incorporate the actual capacity being avoided by the purchase of power from the QF.

DEC/DEP witness Snider testified that the peaker method is designed to determine a utility's marginal capacity and marginal energy cost, and, therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs. He asserted that the Commission has recognized the theoretical corollary of the peaker method, which provides that even if a utility's next planned unit is not a simple cycle peaker, the peaker method still accurately represents a valid estimate of the utility's avoided costs. He further testified that simple cycle CTs represent the lowest capital cost resource option from a fixed cost perspective, and, thus, they are the marginal resource of choice. He further testified that avoided energy costs represent an estimate of the variable costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt hour ($/MWh), include items such as avoided fuel and avoided variable operation and maintenance (O&M) costs. Avoided capacity costs, on the other hand, represent fixed costs associated with construction, financing and staffing of a CT. Witness Snider recommended that the Commission approve the continued use of the peaker method and stated that, if properly applied, the use of the peaker method provides a reasonable and appropriate estimate of the costs that would have otherwise been incurred but for the purchase from a QF facility.

Witness Snider stated that DEC and DEP also believe that application of the peaker method should be refined or modified in several ways. With respect to the calculation of avoided energy rates, he testified that the hourly production cost savings calculated in the system dispatch model should be capped at the production cost of the avoided CT. He stated that this cap simply recognizes that the QF is avoiding the same marginal energy in an hour that the avoided CT would have also avoided, thus, effectively replacing that marginal energy with the CT's lower energy cost. He testified that he believes that capping marginal energy cost in each hour at the avoided energy cost of the CT results in an avoided energy calculation that aligns customer payments for QF energy with the avoidable energy benefit produced by the QF.

DNCP witness Williams testified that it is appropriate for the Commission to revisit the methods used to calculate avoided costs because the existing methods reflect an accumulation of past practices and rulings that no longer accurately reflect DNCP's actual avoided cost. A number of recent changes to the industry justify a re-evaluation of current methods to ensure they are consistent with PURPA. According to witness Williams, for DNCP, the scale of QF development in 2013 and the first quarter of 2014 is over 20 times the total activity seen in the previous five years. As of March 31, 2014, proposed developments total over 600 MW. In comparison, the average load of DNCP's North Carolina service territory in 2013 was less than 500 MW. Witness Williams stated that this shift has had, and continues to have, several impacts: it magnifies the impact of any discrepancies between the sanctioned rates a utility pays for a QF's output and a utility's actual avoided costs; it makes the present biennial avoided cost calculation a less accurate, more dynamic process as the impact of previous QFs on the utility's system can influence the avoided cost of the next incremental QF; and it raises questions with respect to impacts on system operations and reliability of such a sudden development of large quantities of new intermittent resources.

Witness Williams further testified that DNCP does not believe the peaker method, as currently implemented, captures DNCP's avoided costs. He testified that avoided capacity costs should be the fixed costs of the next CT that DNCP plans to build, net of the expected energy benefits from the peaker (i.e., the "Net Peaker" method), in order to address the fact that the peaker method as used in the past disregards the value that a CT provides in energy benefits.

DNCP witness Petrie testified that in the Sub 136 proceeding, DNCP adopted the peaker method for its new Schedule 19-FP, and offered for the first time five, ten, and 15-year levelized fixed prices for projects up to five MW in size. He further testified that the peaker method, with some modifications, is the most appropriate way to calculate avoided energy and capacity costs and, with the changes requested by DNCP, produces an appropriate representation of the Company's actual avoided costs. The current peaker method, however, in witness Petrie's opinion, ignores the non-capacity value of a CT and therefore overstates the calculated avoided cost of capacity. He further testified that, because the QF is already compensated for energy via the avoided energy rate (at the utility's marginal energy cost), the value of the CT energy benefit should be removed from the capacity rate. Under this "Net Peaker Methodology", according to witness Petrie, the avoided capacity costs should equal the fixed costs of the next CT that DNCP plans to build, net of the expected energy benefits, including ancillary service benefits, from the CT. He further stated that this method is now relevant because the CT energy-related benefit was not an important distinction when the peaker method was first used. CT performance – due to technology improvements and reduced heat rates – has improved, and the cost of gas relative to other fuels has decreased. Witness Petrie stated that increased run time means that a CT can deliver substantial benefits in terms of energy, including ancillaries, for customers, producing energy below the wholesale power market price in many hours.

He testified that the Net Peaker Method, in his opinion, is an accepted and common industry approach to determining the value of capacity. The value of capacity method was thoroughly analyzed and discussed by all stakeholders – utilities, generator owners, developers, customers, and regulators in three RTO markets. The outcome in each of the three RTO markets was to adopt the Net Peaker method, and it has been in use since at least 2006 in competitive wholesale electricity markets in the U.S. The FERC has accepted the 'net energy and ancillary services revenue offset' concept in the development of capacity market prices, where the energy and ancillary service related values from a CT are subtracted from the CT construction cost. Finally, the Net Peaker method is also consistent with the analysis conducted by utilities for generation planning purposes, whereby DNCP recognizes that adding a new CT to the system provides both capacity and energy value, and to ignore the energy value would understate the benefits and overstate the capacity cost.

On cross-examination, witness Petrie agreed that over the long run, the price produced by PJM's RPM mechanism does not affect the cost of DNCP's future additions, the 3,800 MW DCNP needs to add in the next 15 years. More specifically with respect to the Net Peaker method, witness Petrie agreed that, generally speaking, the choice of the kind of unit that a utility is going to build depends on how often it expects the unit to run. He agreed that baseload plants are built to meet increases in a utility's base load, which is load that is generally there most of the time, with a nuclear plant being an example of this type of plant. The capital costs are very high, the running costs are not as high, and, therefore, the utility chooses a base load plant if the utility plans to run it in numerous hours.

In response to the question of whether there are any supply-side resources other than a CT, that can be built solely for reliability if the utility does not need the energy and is only attempting to meet a capacity need, witness Petrie testified that a CT facility is the closest facility that he is aware of that approaches pure capacity. He testified that DNCP's revised responses to data requests showed that the new CTs were running with a capacity factor lower than ten percent, but that at this point DNCP was simply placing the concept into the record. To calculate rates, the forward looking energy margins from a new CT would be used. He agreed that if DNCP assumed the CTs ran more hours and that they ran for many short increments, that start costs would be increased, which would increase avoided energy rates using the peaker method. Likewise, higher O&M costs would be incurred.

Public Staff witness Kirsch listed and described numerous methods that can be used to calculate avoided costs and discussed their strengths and weaknesses. With respect to the peaker method, he testified that the strength of this method is that, in theory at least, the marginal capacity costs of all of a utility's resource investments are expected to equal one another in equilibrium. Consequently, the quantitative result is not biased by the choice of one particular technology over another. With regard to the weakness and challenges shared by all methods, he testified that all the methods depend upon data inputs that are uncertain, controversial, or both. Avoided capacity cost estimates depend upon a variety of assumptions about demand growth, construction costs, financing costs, taxes, and so forth. Avoided energy cost estimates depend upon uncertain future fuel prices, capacity factors, heat rates, and non-fuel variable O&M costs of a fleet of generating plants. Because future uncertainties increase with time, methods that depend upon longer-term forecasts are subject to greater error than methods that depend upon shorter-term forecasts, and methods that depend upon forecasts are subject to greater error than methods that depend upon values that are presently known.

On cross-examination, Dr. Kirsch, when asked about the potential for an adjustment to the cost of the CT used for calculating avoided capacity costs because of the improved heat rates and higher capacity factors, testified that the economic theory underlying the peaker method is that the capacity cost of each capacity type is net of the fuel savings attributable to that type. In his testimony, he assumed that a peaking unit would not provide any fuel savings but that fuel savings is not a necessary assumption. In the event that a peaking unit does provide fuel savings because it displaces the power output of old and less efficient power plants, there will be a fuel savings in those hours in which that displacement occurs. However, in those hours in which the new peaking plant is displacing expensive power from old, less-efficient plants, the avoided energy costs in those hours will be the incremental energy costs of those less efficient, high-cost plants. So in going to a net peaker approach, avoided energy costs would need to be calculated on the basis of the high, incremental energy costs of the expensive plants in those hours in which those expensive plants outputs are displaced.

Public Staff witness Hinton testified that the Public Staff supported the continued use of the peaker method. He testified that he reviewed the methods discussed in the testimony of Dr. Kirsch, as well as the testimony filed by other parties. No party proposed that the Commission abandon the peaker method. In view of the testimony of the parties and the Public Staff's investigation, including responses to data requests to several parties, he stated that the Public Staff recommends that the Commission continue to use the peaker method to determine the avoided cost rates for DEC, DEP and DNCP. Witness Hinton testified that DEC, DEP and DNCP indicate future capacity needs in their most recent IRPs. DEC indicates a resource need of approximately 3,358 MWs over the planning period (2013-2028); DEP indicates a resource need of approximately 3,080 MWs over the same planning period, and DNCP indicates a capacity need of approximately 3,802 MWs.

With respect to DNCP's proposed net peaker method, witness Hinton testified that the Public Staff does not agree with the net peaker adjustment. The Public Staff is not persuaded that the energy benefits of a CT can be separated from its primary purpose of providing peak generating capacity at the least cost to the utility. He stated that the Public Staff maintains that this increase in the frequency and run times of newer CTs does not affect the validity of the traditional application of the peaker method. The peaker method has always assumed that CTs are run more than a nominal amount, and, indeed, in the past the Public Staff proposed adjustments because DEC and DEP were running their CTs at much lower capacity factors than assumed. In addition, the Public Staff stated concerns that the large adjustment estimated by DNCP for these energy benefits is largely dependent on DNCP's ability to accurately forecast market prices or LMPs using utility cost production forecasts, which adds a level of difficulty beyond the forecast of the production costs of a CT. He stated that the Public Staff is not convinced that the increased operation of the newer CTs warrants a 30 percent downward adjustment in avoided capacity rates and has concerns that such treatment could violate PURPA. On cross-examination, witness Hinton testified that he does not believe that these new CTs with their lower heat rates will be the last unit dispatched. According to witness Hinton, all three North Carolina utilities have some high oil-fired CTs that will be used during high demand times, despite their high heat rates. He further stated that his biggest concern is that subtracting energy benefits is inconsistent with the peaker method. The actual cost of installing a hypothetical CT is the underlying basis for the peaker method's valuation of capacity. The energy benefits cannot be segregated from the installed cost of a CT simply because current natural gas prices are low and the new CTs are being run more than they were previously run. In addition, estimating how much energy savings might result is very speculative.

In his responsive testimony, SACE witness Rábago testified that DEC and DEP's recommendation to reduce avoided energy rates by the value of "lost production benefits" seems to conflate the concept of sunk costs with the goal of setting fair and non-discriminatory avoided cost rates. Witness Rábago stated that under DEC/DEP witness Snider's formulation, avoided costs should be reduced in the situation where the QF displaces the operation of a utility generation unit that would itself have displaced the operation of non-cost effective, older additional utility generation units that should not have run anyway. So, even where the QF is economical compared to the avoided unit, it must also be cost effective against all the hypothetical costs that the avoided unit avoided by being part of the utility fleet.

NCSEA witness Beach testified that he has concerns in that, compared to other methods for calculating avoided costs, the peaker method tends to produce lower avoided cost estimates because the least-cost capacity option is used as the proxy for avoided capacity costs, even if the utility is planning to build another, more expensive plant. The peaker method depends on the assumption that the utility's system is operating at an optimal point, such that there is no resource other than a low-cost CT that would reduce overall system costs. However, as indicated in the utilities' IRPs, utilities often plan to add resources other than CTs (such as natural gas-fired combined cycles (CCs), which signifies that the utility's system may not always be operating at the "optimal" point of equilibrium. He stated that avoided costs based on the proxy method using the cost of the new plant will be equal to or lower than the avoided cost produced by the peaker method, if the savings in energy costs resulting from the new plant (compared to system marginal energy costs) more than offset the higher capacity costs of the new plant (compared to the least-cost peaker). Therefore, if a utility is planning to add a resource other than a CT, the proxy method may be the more appropriate method to establish the utility's full avoided cost. Given that the Commission determined years ago that the peaker method is an appropriate method for calculating avoided costs for the purposes of the biennial proceeding, the fact that DEC and DEP have used the peaker method for many years, and that both the Commission and the Public Staff are familiar with this method, witness Beach stated that it would be reasonable for the Commission to direct the utilities to continue to use the peaker method to calculate avoided costs. He further stated that the Commission should establish parameters for the inputs used in applying the peaker method. Finally, he testified that the Commission also needs to modify the avoided cost calculation in certain respects to capture more accurately the full range of costs, which solar and other distributed resources allow the utility to avoid.

TASC witness Hornby testified that DNCP's net peaker method should be rejected. He stated that the peaker method is founded on the premise that the utility's long-term avoided cost is its projected system marginal cost of energy in any given hour (which could be from coal units off peak and oil units on peak) plus the fixed cost of a peaking unit. According to witness Hornby, DNCP is essentially proposing that it use the "net cost of new entry" or net CONE method that PJM uses in its forward capacity market. However, he asserted that the net CONE method assumes the owner of the capacity will earn a margin on the sale of energy and ancillary services during peak hours that will equal the difference between the market price of the energy and ancillary services and the owner's cost of providing energy, and that the owner will use that margin to help recover its capital costs. DNCP is not proposing to pay QFs the market price of energy and ancillary services; instead it is proposing to pay QFs its avoided cost of energy. Moreover, he noted, under the peaker method DNCP should pay its avoided fixed cost of capacity, not the QF owner's estimated net cost of capacity. In addition, witness Hornby testified that, consistent with North Carolina's tradition and familiarity, the utilities should continue to use the peaker method to quantify avoided capacity costs using a set of comprehensive, transparent and verifiable input assumptions including land, construction and materials, infrastructure necessary for fuel delivery, and transmission upgrades. The costs should also include all fixed operations and maintenance costs, taxes and weighted average cost of capital.

Witness Hornby also testified that the Commission should reject DEC and DEP's proposal to cap the production cost savings calculated in the system dispatch model at the production cost of the CT that DEC/DEP assumed in its peaker method calculation. According to witness Hornby, the rationale DEC/DEP witness Snider presents for this proposal rests on his premise that DEC/DEP should be calculating the cost of energy it would avoid in each hour by dispatching a gas CT. He stated that this premise is not correct; DEC/DEP should be calculating the cost of energy they would avoid in each hour by purchasing energy from QFs. North Carolina utilities that are planning resource additions other than a new CT in the absence of purchases from QFs should include in their avoided energy costs the net fixed costs of the marginal new resources, i.e., the fixed cost of the marginal resource minus the avoided capacity costs per the peaker method.

On rebuttal, DEC/DEP witness Snider testified that DEC and DEP's rationale for their proposed cost cap adjustment has already been accepted in other jurisdictions. Those that oppose it seem to object to the fact that an avoided CT (within the construct of the peaker method) would serve to reduce a small amount of the marginal energy that the QF is being compensated for in the avoided energy payment. Witness Snider asserted that this adjustment is needed simply to recognize that only the avoided marginal energy benefits above those that would have been created by the avoided CT should be counted in the avoided energy rate calculation.

DNCP witness Williams, in his rebuttal testimony, testified that if the status quo is maintained, DNCP believes the explicit constraints put in place by PURPA would be overstepped, thus providing a subsidy to QF projects above utilities' avoided cost, at the expense of electric utility customers. Also, maintaining the status quo would shift potentially very large risks from the large solar development companies to electric utility customers. He testified that it is critical that the Commission recognize the recent developments in the industry and ensure that the massive surge in development of intermittent QF generation be accompanied by appropriate protections for electric utility customers, who rely on the Commission for oversight of their rates. He further testified that the standard rates that were developed two years ago and that remain in place through November 2014 overstate DNCP's current avoided costs, and there is no mechanism to update them. He also testified that it is inappropriate to maintain the existing method because of significant recent changes in the industry have made the existing rate method inappropriate and no longer in compliance with PURPA. The magnitude of QF development activity has resulted in costs and risks that were once immaterial now becoming potentially large burdens on customers.

DISCUSSION AND CONCLUSIONS

The Peaker Method

In its Order No. 69, the FERC stated the following with respect to ways of determining avoided costs:

> One way is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a QF to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan excluding the QF, over the total capacity and energy cost of the system (before

> payment to the QF) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility. An optimal capacity expansion plan is defined as "the schedule for the addition of new generating and transmission facilities which, based on an examination of capital, fuel, operating and maintenance costs, will meet a utility's projected load requirements at the lowest total cost.

45 Fed. Reg. at 12,214. Thus, at the outset, it is clear that the focus is on the total cost of capacity and energy contained in the utility's capacity expansion plan over its planning cycle with and without QF capacity and energy. This interpretation is reinforced by the inclusion by the FERC in its regulations of Section 292.304(e), which lists the factors the FERC requires be taken into account to the extent practicable when avoided costs are determined.

The question posed in the Commission's Order initiating this proceeding is whether the methods historically relied upon by the Commission to determine avoided cost appropriately capture the full avoided costs. Not surprisingly, the utilities argue that the historically used peaker method overstates avoided costs, while the various intervenors argue that the peaker method understates avoided costs, particularly with respect to solar QFs. In many respects the Public Staff has taken positions that fall somewhat between the other two groups. Despite the wide range of opinions as to the accuracy of the peaker method, there was general consensus that this method be retained.

The Commission has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided costs. Stated simply, the fuel savings of a baseload unit will offset its higher capital costs, producing a net cost equal to the capital cost of a peaker. The Commission has further held that a CT is an appropriate proxy for the capacity-related portion of the total costs of a generating unit that might be added to the system in order to increase system capacity. Thus, avoided capacity costs should equal the cost of a hypothetical CT and, together with the marginal system running costs, these will equal the cost of any generating plant, including a baseload plant. The testimony of the utilities is replete with references to the next CT that they plan to build, even when such a CT is not projected to be needed until after a new baseload plant. They also refer to using "the avoided CT." For example DEC/DEP witness Snider asserts that in calculating of the avoided energy payment, the hourly production cost savings calculated in the system dispatch model should be capped at the production cost of the avoided CT.

The evidence shows that DEC, DEP and DNCP indicate future capacity needs in their most recent IRPs. DEC indicates a resource need of approximately 3,358 MWs over the planning period (2013-2028); DEP indicates a resource need of approximately 3,080 MWs over the same planning period, and DNCP indicates a capacity need of approximately 3,802 MWs. Most of this capacity need is shown as being met with baseload capacity. The Commission finds that the cost of the future baseload capacity in the utilities' capacity expansion plans is the appropriate measure for avoided cost purposes. The peaker method, as it was intended to be used, is a reasonable means of determining this cost and thereby for complying with Section 210 of PURPA.

In regards to DNCP's proposed "Net Peaker" method, DNCP supports it on the basis that the current peaker method ignores the non-capacity value of a CT and, therefore, overstates the calculated avoided cost of capacity. DNCP believes that the current peaker method pays a QF the full fixed cost of a CT (including its energy value) and a separate energy payment equal to the marginal (highest) cost of energy. DNCP, therefore, proposes to remove the value of the CT energy benefit from the capacity rate. Under this "Net Peaker" method, the avoided capacity costs should equal the fixed costs of the next CT that DNCP plans to build, net of the expected energy benefits, including ancillary service benefits, that the CT will provide. The justification is that CTs in the past ran only limited hours per year and, when they did run, they were the unit on the margin (highest cost). Today, a new CT can be expected to run significantly more often, with an annual capacity factor of five to ten percent.

The Commission is not persuaded that DNCP's proposed adjustment is appropriate for approval in this docket. The Commission finds particularly noteworthy DNCP's responses on cross-examination that there are other supply-side resources that can be built solely for reliability if the utility did not need the energy and that a CT facility is the closest facility to be used to identify pure capacity. Finally, witness Petrie's agreement that without a guarantee that wellhead natural gas prices are going to remain in the range that they were in from 2011 through 2013, the years used by DNCP to develop the expected CT capacity factors and therefore energy benefits, DNCP would not build a CT based on the assumption that it needed energy. He acknowledged that DNCP adds CTs because they are needed for capacity. As witness Petrie acknowledged, because CTs are more efficient now, when DCNP builds them, it "happens to get energy benefits that come along with it." A peaker would not be built for capacity purposes if it were not expected to run for some number of hours, otherwise, it would not be needed for capacity.

As TASC witness Hornby pointed out, the "net cost of new entry," or net CONE method, that PJM uses in its forward capacity market assumes the owner of the capacity will earn a margin on the sale of energy and ancillary services during peak hours that will equal the difference between the market price of the energy and ancillary services and the owner's cost of providing energy, and that the owner will use that margin to help recover its capital costs. DNCP is not proposing to pay QFs the market price of energy and ancillary services. Finally, of particular concern is the speculative nature of the estimate of the energy benefits and the fact that DNCP used its proposed method to produce a 30 percent downward adjustment in avoided capacity rates.

Based upon the foregoing, the Commission chooses not to approve DNCP's proposed "Net Peaker" method. A CT is the lowest cost capacity option available to a utility and the fact that the newest CTs, when burning low-cost natural gas, may also produce some energy benefit does not justify the change proposed by DNCP. For many of the same reasons, the Commission determines not to approve DEC and DEP's proposed cap on the production cost savings calculated in the system dispatch model used to determine avoided energy costs. DEC and DEP propose to cap the production cost savings in each hour at the production cost of the CT that DEC/DEP assumed in its peaker method calculation. The rationale DEC/DEP witness Snider presents for this proposal rests on his premise that DEC/DEP should be calculating the cost of energy it would avoid in each hour by dispatching a gas CT. The Commission determines that avoided energy rates should be calculated based upon the cost of the energy the utility would avoid in each hour because of

QF purchases. To the extent these are older, less-efficient generating units, the higher energy costs of such units should be included in the calculation of avoided energy costs.

The Proposal to Include Zeroes in the Calculation of Capacity Credits

In support of DEC, DEP and DNCP's proposal to include zeroes in their avoided capacity cost calculations during the early years of the planning horizon, DEC/DEP witness Bowman testified that, if the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, the QF should not be compensated for providing that benefit. She stated that PURPA was not intended to force utilities to pay for capacity that they do not otherwise need, and both Order No. 69 and subsequent FERC decisions have reinforced this point, citing City of Ketchikan, Alaska, 94 FERC ¶61,293 (2001)(Ketchikan). She also contended that North Carolina law is premised upon this concept in that "a determination of the avoided energy costs to the utility shall include ... the expected costs of the additional or existing generating capacity which could be displaced ... " G.S. 62-156(b)(2). DEC and DEP's recommendation that zero annual fixed capacity costs should be included for years in which no actual capacity need exists merely seeks to effectuate this concept in practice. DEC/DEP suggest that to appropriately incorporate the need for capacity consistent with PURPA, the annual fixed capacity costs that go into the avoided cost rate should include only the annual fixed capacity costs for years in which an actual capacity need exists as determined by the utilities' most recently filed IRP. DEC/DEP witness Snider asserted that the current approach violates PURPA and results in the utilities' customers paying for QF capacity that does not offset needed utility capacity. As a result, retail customers are paying avoided costs for capacity the utilities do not need – in excess of the utilities' avoided capacity cost, as determined under the peaker method.

DNCP witness Petrie testified that avoided capacity costs are zero in the first three years of the 15 years because DNCP, as part of the generation planning process and in order to maintain reliable service for its customers, will have already planned for and procured its projected capacity needs for at least the next three years at any time. This is because it generally requires approximately three years to develop and construct a new capacity resource (such as a CT or CC), and because DNCP must procure capacity in the PJM capacity auctions three years in advance of when the capacity is projected to be needed. Therefore, in the first few years of the planning horizon, witness Petrie asserted that DNCP has all the capacity it needs and that it will not avoid any capacity costs if new QFs commence operation during this time period. Witness Petrie agreed on cross-examination, however, that the price produced by PJM's capacity auction did not affect, over the long run, the cost of DNCP's future capacity additions – the 3,800 MW witness Petrie had agreed DNCP's IRP showed it needed to add in the next 15 years.

NCSEA witness Beach in responsive testimony recommended that the Commission reject the zero value proposals of DEC, DEP and DNCP for the following reasons: First, the FERC's regulations, as well as precedent, provide that the rate paid to the QF is based on future needs. An avoided cost rate should include the full cost of capacity if the QF purchase will permit the purchasing utility to avoid building or buying future capacity. The expected longer-term costs of future additions of capacity must be considered in the calculation of avoided costs and included in the rates based on those avoided costs. In addition, the FERC's regulations explicitly approve determining avoided costs by comparing (a) the total costs that would be incurred by the utility to meet a specified demand without purchases from new QFs to (b) the total costs that would be incurred if the utility purchased power from one or more QFs to meet part of its demand while meeting the remainder through its expansion plan.

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He further testified that the FERC regulations explicitly state that avoided cost rates for purchases from QFs must take into account "the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities." The utility witnesses acknowledge that capacity from solar QFs can be installed with shorter lead times and much more quickly than traditional utility capacity, with construction requiring as little as two months once permitting and such are complete. QF capacity obviously is available in smaller increments, because standard contracts today are limited to no more than five MW. In contrast, typical utility additions of capacity are in much larger increments, as shown by the utilities' current resource plans. These large central station units require significantly longer time to develop, permit, and build. As a result of the long lead times and the large, "lumpy" nature of traditional utility capacity additions, new utility plants are sized to provide much more than the amount of capacity that the utility needs in the year in which the new plant enters service. The result, he explained, is that ratepayers may have to pay for years of extra capacity until demand "catches up" to the last major addition – a fact that is explicit in DNCP's testimony that it has no need for new capacity for the next three years and the conclusion in DEC's and DEP's recent IRPs that, due to the addition of a number of new coal and natural gas units in 2011 through 2013, these utilities do not need capacity until 2016 or 2017. He further testified that, because QF capacity can be built in smaller increments and with shorter lead times, QF development can match more closely the utility's future load growth and future capacity needs, with less excess capacity. The result of this benefit is that QFs can be paid the full value of the CT's capacity in years before the utility has a need, at a cost to the ratepayer that is no higher than what the utility would have incurred "but for" QFs. As a result, it would underpay QFs, in violation of PURPA requirements, if QF capacity rates assume that QF capacity has zero capacity value until the year the next utility unit would be installed.

Witness Beach also testified that, in fact, the utilities' proposal is likely to cause QFs under long-term contracts to always be underpaid. He noted DNCP witness Petrie's testimony that it will always be the case that DNCP will have all the capacity it needs in the first few years of the planning horizon. The result of the utility proposal would be to underpay QFs systematically compared to the utility costs that the QF enables the utility to avoid, in violation of PURPA's full avoided cost principle. He further testified that another problem with the utilities' proposal is that the value of capacity is never zero, even if a utility has excess capacity. There is an active market for short-term capacity in which the North Carolina utilities participate. Even if a utility is "long" on capacity in a particular year, it has an opportunity to sell that excess capacity in the market to earn additional revenues for the benefit of its ratepayers. The value of short-term capacity is apparent in PJM with its organized and visible capacity markets.

Public Staff witness Hinton testified that the Public Staff does not support the utilities' proposal with respect to the inclusion of zeroes. He stated that, while the utilities' position might appear intuitive on the surface, it does not comport with the theory underlying the peaker method. The peaker method is supposed to produce the long-run marginal costs of adding new capacity over the entire planning horizon. For this method to produce the correct total avoided costs, all of the costs of future new capacity have to be included. As a result, the utilities' proposal leads to an understatement of avoided capacity costs and should be rejected if the peaker method is retained.

Witness Hornby testified that witness Snider's recommendation to reduce QF capacity payments for the years in which the utility does not need capacity has two major flaws. First, it has the effect of amplifying pervasive existing incentives for the utility to over-plan and over-build in order to maximize revenues and profits. Second, it effectively precludes ratepayers from ever receiving the benefits of more cost-effective power from QFs except during the imperceptibly small window between a condition of excess capacity and the failure to add utility capacity into the resource plan at some point in the future. That is, QF capacity will almost always be either too early or too late to receive value for its capacity contribution. Under witness Snider's recommended approach, even capacity at a lower price than utility planned capacity will not be fully or fairly compensated.

DISCUSSION AND CONCLUSIONS

The Commission determines that it should not authorize as a generic principle that the avoided cost rate should be reduced as advocated when the utility shows no need to acquire QF capacity when QF contracts are entered into.

Much of the utilities' arguments in this area are premised on the FERC's Order No. 69, particularly as applied in Ketchikan standing for the proposition that the long-term capacity rate calculated under PURPA can be reduced by the inclusion of zeroes in the early years. The Commission concludes that FERC decisions addressing this issue are not uniform and tend to turn on the unique facts of the case before it. Ketchikan involved several towns with electric distribution systems in Alaska that purchased power pursuant to an arrangement established by the Alaska legislature to lower electric rates for rural customers. The FERC granted relief to the towns based upon the relatively unique facts of that case. More recently, however, the FERC rejected claims bearing some similarities to the claims made by the utilities in this case, that a short-term lack of need because of a recently built plant justifies not making capacity payments. In Hydrodynamics (146 FERC ¶ 61,193), the FERC explained that avoided cost rates need not include the cost for capacity in the event that the utility's demand or need for capacity is zero. However, the FERC made clear that the time period over which the need for capacity needs to be considered is the planning horizon. The FERC's quote from Ketchikan is as follows: "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity." Ketchikan, at 62,062. Hydrodynamics involved an installed capacity limit rather than the inclusion of zeroes. Based on the facts of Hydrodynamics, the FERC determined that if a utility needs capacity over its planning horizon, i.e., it can avoid building or buying future capacity by virtue of purchasing from a QF, the avoided cost rates must include the full cost of the future capacity that would be avoided.

The Commission is concerned that including zeroes for the first three years in the calculation of capacity rates lowers the avoided cost rate for the entire 15-year period. Thus, depending on the utility's actual needs over the term of the PPA, the resulting avoided cost rates may not equal the full cost of a CT and system marginal energy costs as a proxy for a baseload plant, as intended by the peaker method. The most recent IRPs for DEC, DEP and DNCP show they need to build or buy over 3,000 MW of capacity over the next 15 years. As conceded by DNCP's witnesses on cross-examination, the cost of that future needed capacity is not changed by the fact that a utility has sufficient capacity in the very near term. Furthermore, while DNCP may not project a need in its first three years due to its participation in the market, it would also be true that the final three years of a QFs long term contract could cover a future need, and, thus, be of more value than the avoided cost rate reflects. It also is significant that the utilities typically are not penalized for having capacity that results in a reserve margin at or above the upper range of what is optimal than they need for the first few years after a large generating unit is placed in rate base. This is in spite of the fact that their ratepayers may be paying a return on most of the investment in the plant for the initial years.

If as witness Snider posited, poor economic conditions, combined with a large influx of QFs, eliminated all future need for utility fossil generation capacity, there would be no future capacity to offset or avoid. The Commission agrees that, under those circumstances, the payment of avoided capacity could be inconsistent with PURPA. That may not be the circumstances in which the utilities find themselves, however. Presently, each of the three shows the need for more than 3,000 MW of generation over the next 15 years, and it is that future generation that QFs can defer or avoid.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10-11

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witnesses Bowman and Snider, the testimony of DNCP witness Williams, the testimony of SACE witness Rábago, the testimony of TASC witness Hornby, the testimony of EDF witness Munns, the testimony of NC Warn witness LaPlaca and the testimony of Public Staff witnesses Brown and Hinton.

SACE witness Rábago addressed a value of solar (VOS) analysis, indicating that it is a method for determining the long-term avoided costs of solar generation. According to witness Rábago, in a VOS analysis, the benefits and costs are first identified and grouped, then quantified. VOS results vary depending on specific methods, local energy markets, and other factors, but a growing body of VOS research consistently demonstrates that solar energy has value that significantly exceeds more narrowly calculated avoided costs. He further testified that a VOS analysis is an improvement over traditional PURPA avoided cost methods because it is a calculation of avoided costs that embraces a full range of costs avoided by solar generation, analyzed over the life of the solar generation system. In other words, VOS analysis achieves a better approximation of the "full avoided costs" associated with solar generation. Consequently, VOS studies illustrate the ability of technology-specific analyses to reveal additional avoided costs that are not captured under traditional avoided cost calculations. He further testified that the benefits and costs studied in VOS analysis generally fall into the following categories: energy (including line losses), capacity (both generation capacity and transmission and distribution capacity), grid support services (also referred to as ancillary services), financial risk (fuel price hedging and market price response), security risk (reliability and resilience), environmental benefits (carbon emissions, criteria air pollutants, and others) and social benefits.

Witness Rábago acknowledged that not all of those values can be quantified with enough confidence that they should be incorporated into avoided cost calculations. In addition, solar generation avoids some costs that may not be appropriately factored into PURPA QF rates, even though those costs are real. Witness Rábago stated that solar energy generation technology, at both the utility and distributed scale, allows utilities to avoid a wide range of costs associated with conventional generation options. Witness Rábago noted a report by Crossborder Energy that found that the benefits to a utility from wholesale solar generation range from nine to 15.6 cents per kilowatt-hour, which are 40 percent greater than a utility's costs to purchase and integrate solar resources. According to witness Rábago, these benefits are inherent to solar generation's innate characteristics – its natural coincidence with peak demand; its ability to avoid transmission capacity costs and line losses by siting smaller systems on the distribution grid closer to load; its scalability; its lack of fuel volatility; and other characteristics.

TASC witness Hornby testified that various studies have quantified at least 14 benefits of distributed solar generation. However, current PURPA regulations only allow utilities to consider eight of those 14 benefits as cost they can avoid by obtaining energy and capacity from QFs. Those eight types of avoided costs to utilities are (i) avoided energy costs (electricity generation), (ii) avoided environmental costs, (iii) avoided capacity costs (generation), (iv) avoided and deferred capacity costs for transmission and distribution, (v) avoided energy losses, (vi) fuel price hedging, (vii) energy market impacts (supply induced price effects) and (viii) ancillary services and grid support. The six additional types of benefits that cause the value of distributed solar generation to exceed the avoided cost rate for purchases from QFs are avoided renewable costs, health benefits, security and resiliency of grid, environmental and safety benefits, effects on economic activity and employment and visibility benefits.

Public Staff witness Brown testified that, to the extent that value categories correspond to actual utility avoided costs, VOS studies can be used to inform utility avoided cost studies. With respect to the eight types of avoided costs recommended by TASC witness Hornby, he testified that he agreed with the first six, which are (1) avoided energy costs (electricity generation), (2) avoided environmental costs, (3) avoided capacity costs (generation), (4) avoided and deferred capacity costs for transmission and distribution, (5) avoided energy losses and (6) fuel price hedging, but did not believe the last two, energy market impacts (supply induced price effects) and ancillary services and grid support**,** could appropriately be measured or otherwise included in avoided costs.

NC Warn witness LaPlaca testified that distributed solar provides a tangible, measurable value to North Carolina's ratepayers, especially because they include a wide variety of energy, capacity, and social and environmental benefits. She stated that utility concerns that solar PV will negatively impact earnings and profits have grown along with the increase in solar installations. She further testified that it is unlikely the growth of solar generation will be a threat to the reliability of the utility grid for many years to come, if at all. She noted a recent General Electric study commissioned by PJM finding that PJM could increase solar and wind to 30 percent without any "significant" issues. According to witness LaPlaca, this study confirms that the grid can integrate high levels of clean energy without compromising reliability.

Witness LaPlaca also presented a summary taken from the Rocky Mountain Institute ("RMI")'s <u>Review of Solar PV Benefit & Cost Studies</u>. This study describes seven major components impacting the value of solar: (1) energy (energy, energy losses); (2) capacity (generation capacity, transmission and distribution capacity, DPV installed capacity); (3) grid support services (reactive supply & voltage control, regulation & frequency response, energy and generator imbalance, synchronized and supplemental operating reserves, scheduling, forecasting, and system control & dispatch); (4) financial risk (fuel price hedge, market price response); (5) security risk (reliability and resilience); (6) environmental costs and benefits (carbon emissions, criteria air pollutants, water, land); and (7) social costs and benefits (economic development, jobs, tax revenue).

TASC witness Smart testified that the Commission's desire to create a broader context in this avoided cost proceeding creates a prime opportunity to address the issue of how to fully and fairly value distributed solar resources. Given the broad scope of potential uses for such a method, she stated that she believes it is appropriate to develop a distributed solar valuation method that is relevant to an avoided cost determination, yet broad and versatile enough to serve the Commission's other foreseeable purposes. Witness Smart further stated that there is no single, recognized method, but that there is an emerging body of literature and technical studies that share common approaches. Her testimony included a compilation of studies and reports that have employed relatively similar approaches to determining the VOS or distributed generation resources. Finally, she stated that there are a few important principles that should inform any inquiry into the VOS: (1) any valuation method of solar should seek to leverage the experience of previous work and follow emerging best practices; (2) a long term perspective on DG value is important to fully capture the benefits DG resources bring to the grid over their useful life; and (3) any valuation method should seek to include the full range of potential values (i.e., all potential benefit and cost inputs) to provide a more informed basis for policy decisions. She recommended that the focus at this stage of the proceeding needs to be on constructing a framework that is inclusive of the full range of values associated with distributed solar.

EDF witness Munns recommended that the Commission continue to use the avoided cost methods approved in the last biennial avoided cost case in setting the avoided capacity payment for solar and wind resources until the Commission develops a more comprehensive method for valuing distributed solar resources. For this more comprehensive approach, she recommended that the Commission develop and adopt a new, stand-alone method for avoided cost rates for distributed solar generation, using a full VOS analysis. Under this approach, the Commission would identify all the costs and benefits attributable to distributed solar generation and develop a value for each element of cost and benefit, the net result representing the full avoided cost of distributed solar generation. She recommended that the Commission or Public Staff hire an independent engineering expert to oversee the VOS study process. She suggested that the Commission start this process now because it will take several months to complete. The Commission would then have an opportunity, following a hearing, to approve, reject, or modify the independent expert's proposal for a distributed solar avoided cost method.

In her supplemental testimony, DEC/DEP witness Bowman responded to the testimony of other parties about VOS studies. She testified that key distinctions make the VOS method inappropriate for establishing avoided costs under PURPA. The most obvious distinction is the method used for the Minnesota VOS study, for example, was designed for a different purpose – to achieve state policies through quantifying and capturing the environmental value of customer-owned solar installations as well as incorporating an array of other values and factors. The

VOS method captures Minnesota's assessment of the full value of distributed solar to the utility, its customers, and society by including asserted environmental and social costs in addition to avoided energy and capacity costs. For example, the Minnesota VOS method includes an avoided "social cost of carbon" as part of the value of distributed solar. She further testified that PURPA does not allow the inclusion of externalities or speculative avoided costs, and such inclusion is antithetical to the fundamental principles of PURPA.

DEC/DEP witness Snider testified that a VOS analysis in the context of setting avoided cost rates is not appropriate because such an analysis includes a list of potential benefits that are not "avoidable utility costs." Furthermore, he stated that such studies ignore certain integration costs associated with intermittent solar generation. He stated that VOS studies fail to recognize and delineate between the specific purpose of avoided cost rates under PURPA and that of policy-driven initiatives like renewable tax incentives, net energy metering and renewable portfolio standards. He further testified that avoided cost rates are appropriately focused on the value of the utility avoided capacity and energy, not on the value of the resource being proposed in place of the utility generation.

DNCP witness Williams testified that DNCP does not reflect some asserted benefits in its rates because the benefits do not result in an avoided cost to the utility itself; the benefits are highly uncertain or speculative; and/or the benefits cannot be realized in the context of a QF, as the utility does not control the development of the facility. Additionally, he asserted that DNCP's proposed avoided cost rate method fully captures these benefits to the degree allowed under PURPA.

DISCUSSION AND CONCLUSIONS

In the Sub 136 proceeding, considerable testimony was presented about VOS and how it should impact avoided cost calculations. In this proceeding, a number of witnesses have encouraged the development of a new, stand-alone method for avoided cost rates for distributed solar generation, using a VOS analysis. Under this approach, the Commission would identify all the costs and benefits attributable to distributed solar generation and develop a value for each element of cost and benefit, the net result representing the full avoided cost of distributed solar generation.

The Commission agrees that integration of solar resources into a utility's generation mix likely results in costs and/or benefits. The avoided costs associated with the energy and capacity produced by QFs have already been discussed and are generally applicable to all QFs. Solar QFs, however, require the consideration of additional factors. At this time, as will be discussed more fully in subsequent sections, hedging and environmental costs can be considered more fully outside the scope of such an integration analysis. Otherwise, the Commission believes it is appropriate for the costs and/or benefits attributed to solar integration to be more fully evaluated when future studies and calculation methods have been further developed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Snider and Makovich, the testimony of DNCP witness Petrie, the testimony of SACE witness Rábago, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Hinton.

TASC Witness Hornby testified that utilities that incur fuel hedging costs have the potential to avoid some of those costs by purchasing from QFs. In addition, even if utilities do not hedge any portion of their fuel supplies, they and their customers still benefit from reducing their exposure to volatile fuel prices. Witness Hornby testified that one approach to estimating the value of avoiding the risk associated with natural gas fired generation is to calculate the difference in cost between buying a specific quantity of gas on a spot basis and buying it at a fixed price under a long-term contract.

The Crossborder study sponsored by NCSEA witness Beach (NCSEA Beach Exhibit 2) indicated that solar generation has no fuel costs, and, thus, avoids the volatility associated with generation sources with costs that depend principally on fossil fuel prices. In its analysis of gas cost forecasts, the Crossborder study indicated that forward market natural gas prices represent a cost of gas that the North Carolina utilities theoretically could fix for the next 15 years, thus, in principle, capturing the fuel price hedging benefit of renewable generation. The Crossborder study also noted that hedging strategies have real costs. For example, DEP incurred $121 million in 2011-2012 in above-market costs to hedge one-half of its 163 billion cubic feet of gas purchases, which reflects a cost premium of $0.74 per MMBtu when spread over the utility's full portfolio of gas purchases. These hedging costs are not included in current avoided cost prices.

SACE witness Rábago also supported the recognition of fuel hedging benefits of solar and other fuel-free renewable generation. He stated that a long-term contract provides a guarantee that the rate paid to the QF will not fluctuate with fuel prices. Witness Rábago testified that for fuel-free resources, in contrast to "traditional" PURPA QFs or other generators that rely on natural gas or biomass fuels, there is no risk that the QF's business will fail due to changes in fuel costs. Witness Rábago testified that quantifying the fuel-price hedging benefits of renewable energy resources may be challenging; however, difficulty is not a justification to set the value at zero.

Public Staff witness Brown testified that PV generation is typically assumed to displace fossil fuel. Because PV generation does not require fuel, and future fossil fuel prices are not known with certainty, to the extent PV generation offsets fuel purchases, it helps to reduce cost uncertainty for the utility. Witness Brown further testified that utilities have the ability to mitigate the impact of fossil fuel price variation on fuel costs by purchasing futures contracts and other forms of hedging. Through hedging, utilities can reduce their exposure to fuel price volatility and provide a financial benefit to the utility and its ratepayers. Even if a utility does not purchase fuel futures, the economic value of avoided fossil fuel usage in a future year can be determined by the futures price. Witness Brown also noted that even if utilities do not use call options or other approaches to hedge its long-term risk of fuel price volatility, pricing models such as the Black-Scholes method can still be used to estimate the value of the hedge.

DEC and DEP witnesses Snider and Makovich both asserted that the value of fuel price hedging should not be considered in avoided cost calculations. Witness Snider classified fuel hedge value as external to avoided costs. Witness Snider testified that the hedge value of solar QF generation is the same as buying forward fuel. On cross-examination, witness Snider stated that "[y]ou can either buy the gas or you can buy the solar both based on the same gas price forecast." He further testified that the major difference with solar is that one is providing a price signal that can be kept constant for two years. He concluded that solar QF generation is a very ineffective way to hedge fuel. Witness Makovich testified that adding solar power could either improve or reduce cost effective risk management. Whether additional solar can add cost effective risk management depends on the utility's current risk exposure and its generation mix, and that cost effective risk management must be accomplished through managing diversity at the generation portfolio level.

DNCP witness Williams, in his responsive testimony, stated that the current actual hedging costs avoided by QF purchases are small, and, therefore, should not be included in an avoided cost calculation. Witness Williams described the "lost option value" of hedging with solar and indicated that the cost of generation will be higher as a result of hedging if actual fuel prices turn out to be lower than forecasted. Witness Williams further testified that using approaches such as the Black-Scholes option pricing model requires an estimate of the future risk-free rate, and an estimate of future fuel volatility, both of which are difficult to forecast with any accuracy over long time horizons.

In his rebuttal testimony, Public Staff witness Brown agreed with the lost option value scenario described by witness Williams, but noted that the converse scenario could be equally true. The cost of generation will be lower as a result of hedging if actual fuel prices turn out to be higher than forecasted. Witness Brown emphasized that fuel price hedging value is based on avoiding volatility and providing price stability, not on forecasting the cost outcomes of any single scenario. Witness Brown stated that "the fuel price associated with solar facilities is known with certainty. Any unhedged fuel that is not purchased due to the output of a solar QF mathematically results in increased predictability and therefore positive hedging value." Witness Brown stated that hedging benefits of solar purchases should only be treated as an avoided cost for the same horizon that the utilities are hedging fuel. As such, witness Brown recommended that the hedging benefits for a solar QF should only be valued over the hedging terms actually purchased by the utility, which in the case of DEC, DEP and DNCP appear to be over a 12- to 24-month term. The cost, according to witness Brown, would be based on current market prices and added to the energy component of the QF rate.

DISCUSSION AND CONCLUSIONS

The Commission agrees with DEC/DEP witness Makovich's testimony that cost effective hedging depends largely on the variability of input fuel prices and the generation portfolio mix of resources, and the Commission further acknowledges that purchasing solar power can be seen as the equivalent of buying natural gas forwards. As indicated in the Crossborder Study and previous DEP fuel adjustment proceedings,[1] a utility's fuel hedging programs to mitigate fuel price volatility can result in significant costs that are borne by ratepayers.

The Commission concludes that there are fuel price hedging benefits associated with solar generation, as well as hydroelectric, landfill gas, and other renewable generation because purchases from QFs are substitutes for the purchase of fuels and reduce the amount of fuel that

[1] Docket No. E-2, Sub 1018, and Docket No. E-2, Sub 1031.

needs to be purchased. It is appropriate to recognize those hedging costs that are avoided as a result of energy purchases from QF generation. The Commission agrees with Public Staff witness Brown, however, that these hedging benefits should only be valued over the hedging terms actually used by DEC, DEP and DNCP. As such, the Commission directs the utilities to calculate and include the fuel hedging benefits associated with purchases of renewable energy in the avoided energy component of its avoided cost rates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Snider and Makovich, the testimony of DNCP witness Petrie, the testimony of SACE witness Rábago, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Hinton.

DEC/DEP witness Snider testified that it would not be prudent to explicitly convert a long range planning assumption related to CO_2 into an immediate cost to consumers in the form of incrementally higher avoided cost rates. Inclusion of CO_2 in avoided energy rates would also expose the utilities' customers to both price and volume risk with respect to their total QF cost obligation since such a price increase would also be accompanied in all likelihood by significant incremental QF participation in North Carolina.

DEC/DEP witness Makovich testified that the price of CO_2 emissions is a "politically determined price designed to influence decision making in specific applications." He argued that lack of consensus on carbon emissions displacement and changes in generation mix and associated emissions dictate that such costs should not be included in the calculation of avoided energy costs.

SACE witness Rábago testified that it is unreasonable to ignore the very real and quantifiable forecast costs associated with carbon emissions. He stated that recently proposed federal carbon regulations will impose costs on utilities within the timeframe of QF contracts set in this proceeding. He argued that this makes carbon regulation a real cost to customers that can and will be avoided by entering into long term contracts with QFs now.

NCSEA witness Beach testified that the utilities' current avoided costs do not include the expected future costs of carbon, even though the utilities base their current resource plans on such costs. For example, he noted that DEC and DEP's IRPs recognize the long-term need to reduce CO_2 emissions by maintaining an option to add nuclear generation. DEC's IRP indicates that "the Company believes that it needs to plan for a carbon constrained future." He noted that the ten- and 15-year avoided energy costs extend into the period during which both DEC and DEP take into account CO_2 emissions costs in their selected resource plans. According to witness Beach, it is unfair to QFs to include these nuclear resources in the production cost modeling used to calculate avoided energy costs while at the same time to exclude from that modeling the CO_2 emissions cost assumptions that are instrumental in selecting these resources for the favored resource plan. Further, given the very long lead times to develop nuclear generation, costs are being incurred today to develop the option to add nuclear capacity after 2020, consistent with the IRPs. Accordingly, he stated that, as recommended in the Crossborder Study, the calculation of avoided energy costs should include CO_2 costs on the same basis as the utilities' IRPs. Excluding such costs results in understated avoided energy credits.

TASC witness Hornby also testified that each utility should include the costs of CO_2 emissions in its production cost simulations to determine avoided energy costs because they all assumed a price for carbon emissions in the Reference Cases of their most recent IRPs. He noted that the carbon emission prices that DNCP used in the Reference Case of its most recent IRP are below the low-case forecast in the Synapse 2014 report, while the carbon emission price that DEC and DEP used in their Reference Cases is somewhat above the Synapse low-case forecast. Finally, he testified that EPA, under Section 111(d) of the Clean Air Act, has the obligation to promulgate performance standards for existing sources of GHG. Thus, it is possible they could place such standards into effect earlier than the federal legislation assumed in the Synapse 2014 forecast.

Public Staff witness Kirsch testified that QF power creates environmental benefits by displacing the electrical energy that would otherwise be produced by resources that are more polluting. In addition, when QF power helps defer or replace new capacity that would be more polluting, it results in the long-term displacement of resources that are more polluting. However, he also testified that, to the extent that utilities do not pay for their emissions, as is the case today for carbon dioxide in North Carolina, QFs do not help utilities avoid costs, even though QF power may provide an environmental benefit.

Public Staff witness Hinton stated that the Public Staff believes that the costs of carbon emissions control are not sufficiently certain at this time to be included in avoided costs. He noted that the Commission has historically held that utilities should not be required to include in their avoided cost calculations externalities that were unknown and uncertain. For example, in its order establishing avoided cost rates in Docket No. E-100, Sub 74, the Commission stated the following: "Quantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." Witness Hinton noted that it is true that the EPA is developing regulations for carbon emission standards from new and existing stationary sources under Sections 111(b) and 111(d) of the Clean Air Act; however, these costs remain speculative and unverifiable. He stated that the Public Staff believes it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable. However, witness Hinton concurred in NCSEA witness Beach's observation that the future generation expansion plans in the avoided cost models are derived from the IRP base expansion plans, which currently include the cost of carbon emissions. This inclusion of carbon is one of the primary reasons the least cost algorithms select new nuclear generation over alternative generation units. He further testified that the apparent inconsistency between the inclusion of assumed carbon costs in the IRPs and the exclusion of such costs in avoided cost production cost models has existed for several years and results from the different purposes of the two proceedings and the different methods utilized in each process.

DISCUSSION AND CONCLUSIONS

While the EPA has proposed to regulate CO_2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time. The end result of the proposed regulations is speculative at best, and, as

Public Staff Hinton noted, the Commission has previously concluded that "[q]uantifying actual out-of-pocket avoided costs is problematic enough without introducing unknown environmental costs into the equation, particularly if such costs would not be out-of-pocket costs to the utility." If and when such costs are known and verifiable, it would be appropriate to revisit this issue and determine whether those costs should be included at that time. However, in the present case, the Commission agrees with the Public Staff that it is inappropriate for ratepayers to shoulder such costs until they become known and verifiable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-19

The evidence supporting these findings of fact is found in the testimony of DEC and DEP witness Snider, the testimony of DNCP witness Petrie, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Hinton.

DEC/DEP witness Snider testified that the following general guidelines should be adopted in the calculation of the annual fixed CT capacity costs: (1) cost estimates should be based on the utilities' most recent study of installed CT costs combined with past construction and operations experience; (2) equipment and construction costs should be based on the cost estimate for a four unit greenfield site; (3) direct CT interconnection costs should be included, but any estimates of downstream transmission and distribution (T&D) system upgrade costs should be excluded; and (4) the equipment and construction costs should represent an expected construction cost with neither a best case nor worst case contingency adder included. He asserted that the annual capacity value of a CT should be calculated incorporating the utilities' most recently approved cost of capital and book life assumptions for a CT, including its recommended 35-year book life. For the contingency adder, he testified that that a five percent contingency adder results in a reasonable expected construction cost.

Regarding DEC and DEP's position that the economies of scale associated with building four CTs at a four-unit CT greenfield site should be used, he testified that DEC's and DEP's demonstrated practice is to build multiple CTs at a single site. He asserted that the multiple unit approach is the most cost-effective approach because it optimizes the economies of scale associated with construction. He stated that the cost of land, site preparation, roadways, gas infrastructure, electric transmission infrastructure, water infrastructure, and administrative and auxiliary buildings is spread across several units (instead of just one or two). On cross-examination, witness Snider agreed that DEC/DEP witness Pintcke testified in the Sub 136 proceeding that generally most of the costs associated with a CT project are EPC (Engineering, Procurement, and Construction) costs, and that the major components of a CT peaking plant construction project are typically the CT itself and the generator step up or GSU transformers. Together, these items account for approximately 60 percent of the EPC costs, while the remainder of the EPC costs are referred to as the balance of plant or BOP costs, which include site work, pre-engineered buildings for plant operators, miscellaneous plant equipment and the like.

With respect to the inclusion of interconnection costs and the exclusion of T&D network system upgrade costs, witness Snider testified that interconnection costs include costs associated with physically connecting the generation source to the transmission system, such as the switchyard and associated equipment costs. He stated that these interconnection costs are included in the calculation of avoided cost rates because they are real costs that will be avoided when the construction of a new CT is avoided and because the QF is fully responsible for the interconnection costs associated with its own facility. Network upgrade costs, he asserted, unlike interconnection costs, involve improvements to the transmission system beyond merely connecting a generation resource to the transmission system. He noted that sometimes a utility’s construction of new generation facilities will require transmission upgrades, but not all new generation additions will. With respect to the appropriate contingency factor, he testified that DEC and DEP believe a five percent contingency adder represents an “expected case scenario” and is appropriate in the context of building a conventional CT for purposes of the utilities’ avoided capacity rates.

DNCP witness Petrie testified that the costs of the next planned CT facility, be it brownfield or greenfield, should be used as the basis of the capital cost of the CT for the calculation of the avoided capacity rate. He stated that DNCP’s next CT is to be developed at an existing brownfield site. He argued that land and other greenfield-related costs should only be included in the avoided capacity rate when the next CT unit will be a greenfield CT. He stated that it was inconsistent to state that CT costs should reflect the utility's future resource plans, but then require DNCP to include costs associated with "a hypothetical CT” that are inconsistent with its actual resource plans. He agreed that the Commission has ruled in the past that DNCP be required to include land costs in its calculation of capacity credits, but only in the circumstances of that proceeding. He asserted that requiring DNCP's ratepayers to bear costs that are not in fact avoided is not just and reasonable, and requiring DNCP to pay capacity rates that include an allowance for land costs that are not avoided will result in the Company paying more than its avoided costs for capacity in violation of PURPA. Witness Petrie conceded on cross-examination that two of DNCP’s most recently completed baseload plants (VCHEC and Bear Garden) were both built on greenfield sites, its future Warren County and Brunswick County plants, both CCs, are both located at greenfield sites. He also agreed that as defined by the Commission, the peaker method is supposed to produce the avoided cost of any generating unit, including a baseload plant.

NCSEA witness Beach testified that PURPA requires that the utility’s future need for capacity be reflected in the avoided cost calculation; as a result, the use of economies of scale that do not accurately reflect the planned peaking capacity additions for a utility is not appropriate and will produce understated avoided costs. Witness Beach recommended that data used to calculate avoided capacity cost should be the same data used to calculate capacity cost in the IRP and the generation reserve margin study. The cost of future generation capacity set forth in the IRP represents the long-run avoided cost of the utility at the time the IRP is filed at the Commission. The filing of the IRPs by the utilities historically has preceded the filing of their proposed avoided cost rates. Therefore, the input assumptions used in the biennial avoided cost proceeding should match those used in the IRPs filed just two months earlier. Second, he recommended that, to the extent the utilities must rely on data other than IRP data, such data should be taken from publicly available industry sources and should not be adjusted. If the utilities use a “generic” or “hypothetical” CT for the purposes of calculating avoided capacity cost or components thereof, such data should be taken from public and transparent industry sources, such as the EIA or PJM cost of new entry studies. He noted that other states with which he is familiar use such public data to determine key avoided cost components. Third, he recommended that the cost components of the installed cost of a CT should be identical to those used in the IRP and reserve margin calculations. The installed cost of a CT consists of a number of cost components that should be included in the total costs of constructing the CT, of obtaining a firm fuel supply, and of connecting the CT to the utility's network. The cost of land and associated site work are typically included in the installed cost of a CT. Fourth, he testified that a utility is likely to incur costs to construct transmission upgrades when CT capacity is installed, particularly when hundreds of megawatts of CT capacity are installed. He stated that not including such costs in the avoided cost calculation understates the utilities' avoided cost and should not be allowed.

Witness Beach argued that the utilities' approach to economies of scale is arbitrary and not based on specific design criteria for what would eventually occur at a site for new CT capacity. He stated that, in his experience, given the size of the North Carolina utilities, the addition of 800 MW of CT capacity at a single time would be unusual, noting that neither DEC's or DEP's most recent IRPs indicate a planned addition of 800 MW of CT capacity.

Public Staff witness Hinton testified that the Public Staff disagreed with DEC/DEP witness Snider's recommendation that the installed cost of a CT should reflect the economies of scale associated with building a four-unit CT facility. As testified by the Public Staff in the Sub 136 proceeding, the Public Staff believes that the assumed economies of scope (building multiple units at the same time) and scale (building multiple units at the same location) should be based on the utility's future resource plans for capacity additions. He further testified that, given the forward-looking nature of the peaker method and DEC's and DEP's resource plans over the next years, there is no indication that either utility plans to build a four-unit CT plant in the reasonable future from which such economies of scope or scale could be realized. As such, he testified that the Public Staff cannot support the assumed cost reduction associated with a four unit site as being reasonable. Rather, the evidence is more supportive of assuming a lower level of savings and therefore the higher costs associated with a two-unit CT site. Witness Hinton stated that it is not uncommon for utilities to build more than one CT unit at the same site to take advantage of economies of scale; however, he argued that for avoided cost purposes, the size of the plant should be a reasonable match for expected annual system load growth. Given DEC and DEP's expected annual load growth, it is not appropriate to assume a CT plant of more than 800 MWs will be built all at one time for purposes of calculating avoided capacity costs.

Witness Hinton further testified that the Public Staff disagrees with DNCP's recommendation to use the costs associated with a brownfield site, as opposed to including the land costs associated with a greenfield site in projecting the installed cost of a CT. The Public Staff has long supported the inclusion of land costs because the peaker method uses a hypothetical CT as a proxy for pure capacity and is designed to approximate the cost of a new baseload plant. While utilities sometimes add capacity at existing sites, they also build capacity at greenfield sites. He stated that the Commission recognized this in Docket No. E-100, Sub 87, when it required both DEP and DNCP to include the cost of land in the calculation of installed CT costs.

TASC witness Hornby testified that the utilities should use a set of comprehensive, transparent and verifiable input assumptions, including land, construction and materials, the infrastructure necessary for fuel delivery, and transmission upgrades. The costs should also include all fixed operations and maintenance costs, taxes and the weighted average cost of capital.

DISCUSSION AND CONCLUSIONS

The Commission notes that the evidence from the Sub 136 proceeding showed that the costs of a four-unit CT used by Astrape for its reserve margin study for both DEP and DEC, including adjustments for economies of scale, were much higher than the capital costs with adjustments for economies of scale proposed by DEP and DEC in the Sub 136 proceeding, using DEP's assumed economies of scale. It appears to be the magnitude of the economies of scale assumed, not the economies of scale themselves, that causes the relatively low proposed installed capital costs. Because the focus of the peaker method is on a "hypothetical CT," for the next phase of this proceeding, the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data. Data on the installed cost of CT per kW taken from publicly available industry sources are to be tailored only to the extent clearly needed to adapt any such information to the Carolinas and Virginia. In addition, to the extent a utility applies economies of scale related to the installed cost of multiple CTs at a single location, the utility should provide detail as to the economies being achieved and the specific components of the EPC contract or balance of plant to which the efficiencies are being applied.

Economies of scale include the cost benefits associated with building multiple CTs at a single site, for example, if only one administrative building were necessary to service a site with multiple CTs the entire cost of the building could be divided among the units when calculating the costs associated with a single CT. Economies of scope include the cost benefits associated with building multiple CTs at the same time, for example, if a utility were to build multiple CTs at the same time it could conceivably purchase discounted bulk materials and save on employee training etc. The Commission agrees with the utilities that it is appropriate to incorporate economies of scale for the construction of up to four CTs at one site in its calculations. The utilities have demonstrated that such a practice is historically supported and reflects the most likely proxy of future hypothetical CT construction. However, the Commission also agrees with the Public Staff and other parties that it is unlikely that four CTs will be constructed at the same time. The same evidence supporting the inclusion of economies of scale supports the exclusion of economies of scope as the utilities are likely to build at the same site but only to add one CT at a time. Thus, the Commission finds it appropriate to include economies of scale, for up to four units, in the calculation of the installed cost of a CT. Further, the Commission concludes that it is inappropriate to include economies of scope in the calculation of the installed cost of a CT.

The Commission concludes that transmission system impacts, a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, and a reasonable estimate of useful life of a CT are appropriate to include in the calculation of the installed cost of a CT and should be included in the calculation of avoided capacity costs.

With regard to DNCP's argument against the inclusion of land, the peaker method uses a hypothetical CT as a proxy for pure capacity and is designed to approximate the cost of a new baseload plant. New baseload plants typically are built at greenfield sites, which is demonstrated by DNCP's testimony. The Commission concludes that DNCP should be required to include the cost of land in the calculation of installed CT costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-22

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Bowman and Snider, the testimony of DNCP witnesses Williams and Petrie, the testimony of NCSEA witness Beach, the testimony of TASC witness Hornby and the testimony of Public Staff witness Ellis.

DEC/DEP witness Bowman testified that DEC and DEP recommend that the Commission continue its current practice of approving standard rates that pay capacity credits on a per-kilowatt-hour (kWh) basis and that it eliminate multiple definitions of peak and off-peak hours within the tariff structure by eliminating DEC's and DEP's respective Option A schedules.

DEC/DEP witness Snider testified that in recognition of the deliverability challenges faced by smaller intermittent QF resources, DEC and DEP recommend that annual capacity be paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the most likely hours to which capacity will have value. He recommended that avoided capacity credits be paid only between the hours of 2:00 p.m. and 7:00 p.m. on non-holiday weekdays during June, July, and August; and between 6:00 a.m. and 9:00 a.m. on non-holiday weekdays during December, January, and February. He asserted that these are the hours that are most influential in resource addition decisions from an IRP perspective as they represent the hours that are within five percent of the load in the highest peak load hour in the summer and in the winter. Witness Snider argued that it would not be appropriate to maintain the current Option B hours within DEC's and DEP's standard tariffs. He further testified that the standard tariff should define a single set of hours as on-peak and that the different definitions between Options A and B allow QFs to choose the definition that produces the most revenues for the QF relative to their operations. He postulated that, while this is beneficial to the QF, it leads to an overstatement of the actual avoided energy benefit since each QF picked its option based on revenue optimization rather than a consistent definition of peak hours based on the utilities' avoided energy cost.

DNCP witness Williams and Petrie testified that DNCP currently calculates avoided capacity payments on a dollars per kWh basis and that it is appropriate to continue to calculate these payments in this manner because it is relatively simple and reasonable because it pays the QF for capacity based upon its contribution to support customer demand during DNCP's on-peak hours. In addition, witness Petrie testified that calculating the avoided costs on a per kWh basis avoids the need for performance testing or complicated availability metrics that would be required under a payment method based on installed capacity ($/kW). DNCP witnesses Williams and Petrie both testified that paying on an installed capacity approach would require the determination of the proper reliable capacity of the resource in kWs, which is a difficult proposition for intermittent resources.

Witnesses Williams and Petrie both recommended that both Options A and B be eliminated and that a narrower band of on-peak hours and only one definition of on-peak hours be used for both energy and capacity. Witness Petrie proposed that capacity payments be limited to those months and hours that best reflect a facility's capacity value. He testified that this is from 2:00 p.m. to 7:00 p.m. on non-holiday weekdays during June, July, and August; and from 7:00 a.m. to 9:00 a.m. and from 6:00 p.m. to 8:00 p.m. on non-holiday weekdays during January and February.

He recommended that only one option be approved because providing multiple options unnecessarily complicates the process and potentially provides options that do not align appropriately with avoided cost principles. According to witness Petrie, for energy, the definition of peak hours should include hours when customer demand is high and when higher cost resources are likely to be dispatched to serve load, which is from 10:00 a.m. to 10:00 p.m. on non-holiday weekdays during April through August, and from 6:00 a.m. to 1:00 p.m. and from 4:00 p.m. to 9:00 p.m. on non-holiday weekdays from October through March.

NCSEA witness Beach testified that Option B represents a reasonable first step for implementing a capacity factor method in North Carolina, as it allows a solar QF to earn capacity credits based on whatever capacity factor it can achieve from its output over the Option B period. However, he testified that Option B should be refined to align more accurately with the utilities' system peaks, thus providing greater benefits to the utility and ratepayers. Specifically, he recommended that Option B should be refined to move the range of hours in the summer from 1:00 p.m. until 9:00 p.m. to 11:00 a.m. until 7:00 p.m. for DEC, and to noon until 8:00 p.m. for DEP. For DEC, for the years 2010-2012, an on-peak period of 11:00 a.m. to 7:00 p.m. captures 69 percent of these peak load hours, compared to 63 percent for a 1:00 p.m. to 9:00 p.m. on-peak period. For DEP, an on-peak period of noon to 8:00 p.m. captures 59 percent of the peak load hours, compared to 58 percent for a 1:00 p.m. to 9:00 p.m. on peak period. He testified further that a summer peak period of from 11:00 a.m. to 7:00 p.m. or from noon to 8:00 p.m. is a reasonable compromise among the on-peak periods used in the non-residential retail rate designs of the North Carolina utilities.

TASC witness Hornby testified that DEC/DEP witness Snider's recommendation would pay for capacity in only 514 hours per year and that this proposed rate design does not satisfy generally accepted principles of utility rate design and discriminates against QFs relative to DEC and DEP. He noted that DEC and DEP have the opportunity to recover their capacity costs over many more hours per year than that proposed for QFs. He further testified that no other DEC or DEP tariffs use an on-peak period of from 2:00 p.m. to 7:00 p.m. in the summer and from 6:00 a.m. to 8:00 a.m. from December through February. Under their rate schedules with demand charges, DEC and DEP have the opportunity to recover capacity costs by applying those demand charges in on-peak periods that range from 1,564 hours to 1,864 hours per year, which are the times that the capacity and energy have the most value. At the same time, they are proposing that QFs be limited to only 514 hours. Witness Hornby stated that this is inconsistent with the testimony of Jeffrey Bailey in DEC's most recent rate case in Sub 1026. According to witness Hornby, Witness Bailey testified that capacity and energy have the most value to residential customers in 1,524 hours per year. The Time of Use price offerings for residential and nonresidential customers have on-peak hours from noon to 6:00 p.m. on weekdays from June through September and from 7:00 a.m. to 1:00 p.m. on weekdays from October through May. He stated that DEC and DEP could provide no analysis in response to data requests in this proceeding to support any of their recommendations.

Public Staff witness Ellis provided the history of Option B, which was initially proposed by DEC in 2002, in Docket No. E-100, Sub 96. Witness Ellis testified that Option B is consistent with the FERC's Order No. 69. He stated that because DEC, DEP and DNCP are all summer peaking systems, it is appropriate to consider the value of the power provided by generating systems that operate during these times of higher customer demand and to encourage production during periods of time when the cost of the utility-generated electricity is greater. Witness Ellis also testified that, with regard to summer peaks, solar QFs in North Carolina generally generate electricity during the hours with the higher system peaks. He noted that there is a significant alignment of solar output from facilities located in the state with the summer hours during which the North Carolina utilities experience their highest loads and at least partial alignment with the utilities' highest one-hour peak loads. He further noted that for winter peaks, which generally occur in the early morning hours, solar output is greatly reduced, as is its contribution to meeting the highest peak demands of the utilities' systems. He stated that, as discussed in some detail in the Sub 136 proceeding, in a typical configuration, the output of a typical solar photovoltaic system will be at its maximum earlier than a utility's one-hour system peak load, with the result that only a portion of the solar output is available to offset that one-hour peak load. However, if a solar QF has the option of receiving a higher capacity credit during the higher cost on-peak hours, as is done in Option B, it could design its facility so that its output is a better match to the system's demand. The installation of tracking systems and changes such as an adjustment to the tilt or azimuth of fixed solar panels for the purpose of maximizing electricity generation during the specified critical on-peak hours can be used to accomplish this.

Witness Ellis testified that allowing this option is beneficial to ratepayers because under Option A type rates, avoided capacity costs are spread out over all of the hours that are considered on-peak, which for DEC, for example, are 4,160 of the 8,760 total hours in a year. The division of the avoided capacity cost by this large number of hours results in a lower kWh rate than would result if a smaller number of on-peak hours were used. If only an Option A type rate structure is available, a solar facility would likely choose to configure its system to maximize total electricity output during all of the on-peak hours, regardless of the timing of its generation relative to a system's peak load. While this benefits the system in that the utility's load is increasing at the same time as the solar output increases, the solar output would provide greater benefit if it were better matched to the utility's load. This justifies a rate structure that leads to the maximization of electricity generation during the specified higher cost on-peak hours.

With respect to Option A, witness Ellis testified that the Public Staff believes that Option A is still appropriate for some technologies and that the existence of two options is not administratively burdensome. The purpose of maintaining the two options for QFs is not to maximize the revenues of a QF, as characterized by DEC-DEP witness Snider, but to recognize the differing operating characteristics of resources utilized by QFs and to allow them an opportunity to earn their full avoided capacity costs in a nondiscriminatory manner. In addition, he noted that the Public Staff does not believe that it would be appropriate to dramatically narrow the on peak months and hours as proposed by DNCP. Witness Ellis stated that NCSEA witness Beach's proposed tailoring of the on-peak hours to utility peak load warrants further consideration.

On rebuttal DEC/DEP witness Snider testified that he disagreed with the Public Staff's recommended continuation of Option A and Option B hours because he believes that allowing multiple avoided cost definitions of peak capacity hours for the same utility will, by mathematical definition, result in customers overpaying for QF capacity relative to the avoided cost value the QF's create. He stated that this overpayment stems from individual QFs having the ability to choose from multiple peak definitions that maximize their revenues rather than choosing the peak definition that represents the utility's true avoided capacity cost. Also on rebuttal, DNCP witness Williams expressed the same concern, when afforded these options, he stated, developers will select the option that produces the highest revenue for them, which means the highest cost for electric utility customers, regardless of which option best reflects true avoided cost.

On rebuttal, Public Staff witness Ellis stated that the Public Staff does not agree to DEC/DEP witness Snider's rationale for limiting the hours. While the costs of a combustion turbine are used as a proxy for pure capacity cost under the peaker method, witness Snider's analysis and recommendation treat QF generation as if it only has capacity value if it operates as a peaking resource. This is not an appropriate application of the peaker method. He stated that in numerous proceedings the Commission has recognized that QF capacity has value in hours other than the very narrow band of hours surrounding the expected summer and winter peaks identified by witness Snider. In addition to the foregoing, he testified that allowing a QF the opportunity to receive a capacity payment only during the narrow number of hours and months proposed by witness Snider raises the question of reasonableness, considering that the capacity factors of utility-owned solar and hydroelectric generation indicate that it would be difficult for these generating facilities to recover their capacity costs if they were held to the same standard. He noted that both DEC and DEP's IRPs show a significant need for non-peaking capacity over the next 15 years.

Witness Ellis further testified that the Public Staff conducted its peak load analysis to identify the hours that, for illustrative purposes, are within ten percent of the annual seasonal peaks over the period of 2006 to 2013, the period over which data were readily available. The results of that analysis were set forth in Ellis Exhibits 1 and 2. This analysis indicates that there is a significant need for capacity during the summer between the hours of 12:00 p.m. and 9:00 p.m., with the highest concentration of peaks being between the hours of 1:00 p.m. and 8:00 p.m. The analysis also shows that there is a significant need for capacity during the current non-summer months, with the highest concentration of peaks between 6:00 a.m. and 10:00 a.m., but an additional significant number existing between the hours of 1:00 p.m. and 9:00 p.m. This capacity need is present even if the focus is limited to witness Snider's analysis of peaks within five percent of the annual seasonal peaks. Witness Ellis stated that this illustrates that capacity is needed and has significant value outside of the narrow window advocated by DEC-DEP witness Snider.

DISCUSSION AND CONCLUSIONS

No party to this proceeding recommended that the Commission begin to calculate avoided capacity payments based on a per kW basis, rather than continuing to use the per-kWh capacity payment. The utilities focus was on eliminating options and narrowing the hours over which they would pay capacity, while NCSEA and TASC focused on tailoring the hours to better accommodate the particular characteristics of solar QFs. The Commission agrees with the Public Staff that it is too soon to abandon the offering of Option B, leaving only Option A, so soon after DEP and DNCP stipulated to offering an Option B, with avoided capacity rates calculated using the same on-peak hours as used by DEC in its currently effective Option B rates. The Commission approved the stipulation and included this requirement in its February 18, 2014 Order Establishing Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 136, shortly before it issued the order initiating this proceeding.

The Commission finds merit in the Public Staff argument that QF generation has capacity value at times other than the peak hours. Also, the fact that a QF would evaluate and choose one set of hours to maximize its revenue does not mean that this automatically results in costs higher than avoided costs. The offering of two sets of hours allows QFs to tailor their production to the times that the utilities have the greatest need and recognizes that different resources may provide energy under different time schedules resulting in the same value to the utility. The Commission has recognized in earlier proceedings that QF capacity has value in hours other than the very narrow band of hours surrounding the expected summer and winter peaks identified by the witnesses for DEC, DEP and DNCP. For example, DNCP witness Petrie testified on rebuttal in the Sub 136 proceeding that DNCP was not opposed to adding an Option B type rate offering (so long as the PAF used in the Option B rate offering is 1.2), noting that the definition of on-peak hours in Option B is consistent with customers' current demand patterns, and covers those hours when the system is most likely to experience its peak load. The Commission notes that the hours proposed in this proceeding are not consistent with the on-peak hours and months used for the utilities' Time-of-Use rate schedules.

The Commission concludes that DEC, DEP and DNCP should continue to calculate and include in their avoided cost rate schedules both an Option A and an Option B, with the avoided capacity rates in Option B calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreement entered into among DEC, DEP and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-25

The evidence supporting these findings of fact is found in the testimony of DEC/DEP witnesses Bowman and Snider; the testimony of DNCP witness Petrie; the testimony of NCSEA witness Beach; the testimony of TASC witness Hornby; the testimony of NC Hydro Group witness Givens; the testimony of NC WARN witness LaPlaca; the testimony of Public Staff witness Ellis; and the stipulation amongst DEC, DEP and the NC Hydro Group.

DEC/DEP witnesses Bowman and Snider testified that DEC and DEP are proposing to reduce the PAF to 1.05 to align its application better with the reliability of a natural gas CT, the unit which the QF is presumed to avoid under the peaker method. DEC and DEP's witnesses opposed increasing the PAF for solar and other resources to 2.0, but testified that for existing small hydroelectric QFs, a PAF of 2.0 would continue to be used.

NCSEA witness Beach testified that DEP/DEC witness Snider incorrectly characterizes the PAF as a multiplier that "increases the avoided capacity rate paid by customers and received by the QF." To the contrary, witness Beach stated that the Commission has explained, in the context of discussing a higher PAF for hydro facilities, the use of a PAF does not exceed avoided costs; it simply changes the method by which avoided costs are paid. He noted that the use of a PAF in the calculation of avoided cost rates when using the peaker method is a tradition of long standing in North Carolina. The PAF accounts, in part, for the fact that the QF, like any generating facility, cannot be in operation at all times. The Commission has recognized this fact in the past, in rejecting a prior DEC proposal to reduce the PAF to 1.08, again based solely on the availability of the avoided peaker. He noted that in that order, the Commission determined to retain the 1.2 PAF, and concluded:

> While the peaker methodology (sic) employed by PEC and Duke relies on the cost of a combustion turbine to provide the purest estimate of avoided capacity costs, the fixed costs of a peaking unit represent a proxy for the capacity related portion of the fixed costs for any avoided generating unit. Thus, the availability of a CT is not determinative for purposes of calculating a PAF.

Witness Beach recommended that that the Commission make no change, at this time, to the current PAF structure, stating that the PAF of 1.2 for non-hydro QFs is a reasonable means to adjust the way QF capacity payments are made.

NC WARN witness LaPlaca testified that she believes the current PAF for solar is too low and should be revised upward to at least 2.0 for a number of reasons, including "the high value of solar during peak summer hours, the fact that solar displaces purchased and hedged fuel for 25 years, reduces water use, reduces pollution and reduces waste treatment and storage," all of which she states add value for North Carolina's ratepayers.

Public Staff witness Ellis described the PAF and its history and noted that the Commission has consistently recognized in its avoided cost orders over the years that the purpose of the PAF is to allow a QF to experience a reasonable number of outages and still receive the capacity payments that the Commission had determined constitute the utility's avoided capacity costs. More specifically, the Commission has recognized that, because standard capacity rates are paid on a per-kWh basis, setting avoided capacity rates at a level equal to a utility's avoided capacity cost without a PAF would require a QF to operate 100 percent of the on-peak hours throughout the year in order to receive the full capacity payment to which it is entitled. He stated that a 1.2 PAF allows a QF to receive the utility's full avoided capacity costs if it operates 83 percent of the on-peak hours. He noted that the Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. Witness Ellis further testified that, despite repeated challenges to the PAF, particularly from DEC, the Commission has consistently reaffirmed the use of a 1.2 PAF in the calculation of the utilities' avoided capacity rates.

Witness Ellis stated that the Public Staff finds some merit in the positions of both the utilities and the QFs. There are a number of methods being utilized across the nation to spread capacity payments, all of which are intended to meet the intent of PURPA. He stated that the Commission's prior approvals of the PAFs and the availability of Option B type rates meet the literal requirements and the intent of PURPA. Witness Ellis testified that the Public Staff believes that the reduction of the PAF to 1.05 as proposed by the utilities is unjustified. The Commission has repeatedly concluded that the use of a 1.2 PAF reflects its judgment that, if a QF is available 83 percent of the relevant time, it is operating in a reasonable manner and should be allowed to recover the utility's full avoided capacity costs. He stated that performance at that level is commensurate with a baseload plant under any definition. He further stated that none of the data provided or arguments made is persuasive to justify a departure from that conclusion. In this regard, it should be considered that when the capacity factors reported by the utilities in their monthly baseload power plant performance filings are averaged over the last three calendar years, none of them operated their baseload fleet at an 83 percent capacity factor, which is the relevant statistic for comparison because QFs are paid for capacity on a kWh basis. For the calendar years of 2011, 2012, and 2013, the baseload plants in the rate bases of DEC, DEP and DNCP averaged capacity factors of 75.67 percent, 74.52 percent, and 74.83 percent, respectively, while recovering all of their capacity costs through rates.

With regard to run-of-river hydro, witness Ellis recounted that starting in 1997, on the ground that it was necessary to put the QFs on equal footing with the utilities' run-of-river hydro in rate base, the Commission ordered that a PAF of 2.0 be utilized by both DEP and DEC in their respective avoided capacity cost calculations for hydroelectric facilities with no storage capability and no other type of generation. The use of a 2.0 PAF requires a QF to operate 50 percent of the on-peak hours in order to collect the full capacity credit.

NC Hydro Group witness Andrew Givens testified that the performance characteristics and capacity value of the small independently operated run-of-river hydro facilities are very similar to the utility owned run-of-river hydro. Witness Givens also stated that the capacity credit paid to a non-utility should fully compensate it for the total installed capacity of the hydro plant. He further stated that this is necessary in order to provide equitable treatment with the utilities' run-of-river hydro in rate base. He stated that over the past nearly 20 years the 2.0 PAF has been in effect, QF hydro plants have faced financial difficulties with rates that have been too low and unstable. His recommendation is that, if the PAF method is used in the future, an increase to a level significantly above 2.0 is considered.

The June 24, 2014 stipulation amongst DEC, DEP and the NC Hydro Group agreed to use a PAF of 2.0 for run-of-the-river hydroelectric facilities in proposed rates until December 31, 2020.

DISCUSSION AND CONCLUSIONS

In its Order dated September 29, 2005, the Commission specifically concluded that the availability of a CT is not determinative for purposes of calculating a PAF because the fixed costs of a peaking unit are only a proxy for the capacity-related portion of the fixed costs of any avoided generating unit. While the Commission stated in its order initiating this proceeding that it would revisit its precedents, it determines that the arguments for altering the PAF are insufficient to modify the PAF at this time. As discussed earlier, the Commission determines that there has been widespread QF development under the existing framework without adverse impacts to utility ratepayers. There is no evidence that the current framework fails to comply with the requirements of Section 210 of PURPA or otherwise disadvantages QFs. Absent such evidence, the Commission determines that the conflicting evidence presented in this docket justifies its continuation going forward. The Commission agrees with NCSEA and the Public Staff that the 1.2 PAF should continue to be used by DEC, DEP and DNCP in their respective avoided cost calculations for all QFs other than run-of-river hydro.

With regard to the 2.0 PAF for run-of-river hydro, no party objected to the stipulation among DEC, DEP and the NC Hydro Group, and the Commission concludes that it should be approved. As the Commission and the General Assembly have traditionally supported run-of-river hydro through specific policies and findings, the Commission finds that it is appropriate to discontinue the use of the 2.0 PAF in accordance with the stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-27

The evidence supporting these findings of fact is found in the testimony of DEC/ DEP witness Snider; the testimony of DNCP witnesses Williams, Wright and Bailey; the testimony of EDF witness Munns; the testimony of NC WARN witness LaPlaca; the testimony of NCSEA witness Beach; the testimony of SACE witness Rábago; the testimony of TASC witness Hornby; and the testimony of Public Staff witnesses Brown and Hinton.

Ancillary Services and Integration Costs

DEC/DEP witness Snider testified that intermittent QF resources, specifically solar, create integration costs. Witness Snider sponsored as Snider Exhibit 1 the Duke Energy Photovoltaic Integration Study conducted by Pacific Northwest National Laboratory (PNNL Study). Witness Snider recommended that the Commission recognize the integration costs associated with the increased reserve requirements in the Generation section of the PNNL Study that result from the increase in net load variability due to solar PV penetration. Witness Snider recommended that the Commission authorize DEC and DEP to adjust their avoided energy rates to reflect the PNNL study results at the level reflected in the Compliance case, which aligns with the IRP assumptions for PV penetration and was the lowest penetration level considered.

Several parties, including EDF witness Munns, NC WARN witness LaPlaca, SACE witness Rábago, and TASC witness Hornby included grid support or ancillary services as a possible category of solar generation benefits. Public Staff witness Brown testified that existing PV generation facilities are not capable of providing reliable grid support or ancillary services, and that current electrical codes generally preclude inverters that provide ancillary services. Public Staff Witness Brown noted, however, that there are current discussions about potentially modifying the interconnection standard (IEEE 1547) to accommodate inverters capable of providing grid support services. Witness Brown noted that once PV generation facilities are capable of providing grid support, it may be appropriate to evaluate these capabilities to determine whether the services provided result in a utility avoided cost.

NC WARN witness LaPlaca testified that when variable generation resources are spread out over a larger geographic area, and fuel cost savings are included, overall costs are reduced. Public Staff witness Brown agreed that larger balancing authorities can result in a reduction in overall reserve requirements, and that there may be dispatch benefits when aggregating intermittent generation over larger geographic areas due to increased predictability of aggregate information, but noted that the variability from intermittent generation still increases reserve requirements and utility costs.

TASC witness Hornby and NCSEA witness Beach testified that they agreed that generation-related solar integration costs may exist, but they indicated that studies, including the

PNNL Study indicate that other solar integration benefits may offset the costs, even at higher levels of solar penetration.

Avoided Transmission and Distribution Capacity

Public Staff witness Brown testified that PV generation may result in avoided transmission capacity benefits to the extent it has the effect of reducing retail electricity purchased from the utility. The power generated by distribution-connected PV facilities does not utilize the transmission system. Therefore, the transmission system does not have to supply any power generated by distribution-connected PV facilities. Witness Brown noted that any generating facility can be located on an existing transmission system at a place that can reduce power flows on heavily loaded transmission lines, but these benefits are highly dependent on siting. On the distribution side, Witness Brown indicated that potential distribution capacity benefits are dependent upon (1) the extent to which the existence of PV has the effect of reducing power flows at the feeder and distribution substation level, and (2) the planning criteria used by the utility. Because distribution feeders have a small geographical footprint and PV generation may not always occur during particular periods of peak load (e.g., due to cloud cover), there is the risk for potential equipment overloads. Therefore, it may be appropriate for a utility to set capacity planning criteria assuming no PV generation, which results in no distribution capacity benefits for PV generation.

NCSEA witness Beach testified that small, distributed QFs with output during the hours of peak demand that is consumed on the distribution system will reduce peak loadings on the transmission system, will make more capacity available on the transmission system to serve load growth, and will allow the utility to avoid building new transmission capacity. He further testified that these avoided peak-related transmission costs are distinct from other generation-related transmission costs associated with interconnecting the avoided generation resource (i.e., a peaker). Witness Beach recommended that the Commission follow the recommendations of the Crossborder Study, in which long-term avoided transmission capacity costs for DEC and DEP were calculated using the NERA regression method, an approach that calculates how a utility’s transmission investments change as the demand on its transmission system varies. Witness Beach testified that for DNCP, the Crossborder Study used the PJM rate for network integrated transmission service as a more direct measure of the costs which DNCP can avoid if solar reduces DNCP’s peak demand on the PJM grid.

TASC witness Hornby recommended that DEC and DEP use the results of the Crossborder study for avoided transmission cost calculations, and that DNCP use the PJM Network Integrated Transmission Service Rate, adjusted by a 46 percent capacity rate for solar facilities, for avoided transmission capacity cost calculations.

DEC/DEP witness Snider testified that the companies recognize there are potential operational challenges from integrating intermittent generation. DEC and DEP believe a more comprehensive impact analysis is necessary before such a recommendation could be made by a utility, and they are therefore not recommending the addition of transmission and distribution integration costs at this time.

DNCP witnesses Wright and Bailey testified regarding the impact of additional intermittent QF generation on the DNCP transmission and distribution systems. Witness Bailey testified that it is not clear whether additional solar QF generation in DNCP's service territory would actually act to increase or decrease transmission capacity costs. Some of the considerations include lower growth and congestion in the DNCP's North Carolina service territory, the intermittent nature of solar generation, the potential for reverse flow, and winter peak planning requirements. DNCP witness Williams also testified that since DNCP does not control the placement, timing or dispatch of QF facilities, the potential transmission or distribution benefits that can be achieved with the deployment of distributed generation are reduced.

Public Staff witness Brown disagreed with witnesses Beach and Hornby that the Crossborder findings were adequate for establishing avoided transmission costs, and noted that it may not be appropriate to utilize costs from the PJM service territory and their assumed capacity factors for determining avoided costs related to DNCP transmission capacity in North Carolina. Public Staff witness Hinton testified that the Public Staff believes the avoided transmission and distribution model currently used by DNCP in its cost-effectiveness tests for demand side management (DSM) and energy efficiency (EE) programs may be appropriate to use for avoided cost calculation purposes if the demand reductions from solar generation were found to warrant avoided cost treatment. In addition, witness Hinton indicated that DEC is currently revising its existing avoided T&D cost model used for DSM/EE cost-effectiveness purposes. Public Staff witness Brown testified that this model, once revised, may provide a better tool for evaluating the appropriate avoided transmission capacity benefits that a solar QF may provide.

<u>Line Losses</u>

NCSEA witness Beach, SACE witness Rábago, TASC witness Smart, and TASC witness Hornby testified that distributed generation can provide transmission and distribution line loss benefits and noted that Section 292.304(e) of PURPA, which provides factors for determining avoided costs includes "the costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity." They also noted that the Commission has long recognized line losses at both the distribution and transmission level as an appropriate consideration in determining avoided costs.

Public Staff witness Brown testified regarding line losses in greater detail, noting that the transmission line loss benefits of solar generation, and recognized that the power generated by distribution-connected PV facilities does not utilize the transmission system. Therefore, distribution-connected PV facilities will result in lower transmission losses. PV facilities that are connected to the transmission system, like utility owned generating facilities, can also result in lower transmission losses depending upon where they can be placed on an existing transmission system. On the distribution side, witness Brown testified that PV generation interconnected at the distribution level may result in line loss benefits by serving local load that would otherwise be served by the distribution system, but utility-scale PV facilities connected to the transmission system do not affect distribution system losses.

NCSEA witness Beach testified that the current avoided cost calculations used in North Carolina correctly are based on the assumption that QF generation helps avoid transmission line losses. However, these losses are calculated assuming a baseload load profile, while solar generation produces power principally during the daytime, higher demand hours, when line losses are higher than average. As a result, he stated that solar avoids more transmission line losses per kWh of output than baseload generation. Witness Beach stated that this fact was noted in the Crossborder Study but that it lacked adequate data to quantify with specificity the additional transmission line loss savings attributable to solar. Based, however on the findings of the PNNL study, witness Beach and witness Hornby recommended that DEC and DEP include a 3.3 percent adjustment to both energy and capacity credits, and that DNCP also use a 3.3 percent adjustment to both energy and capacity credits until a comprehensive study within DNCP's territory can be performed.

Witness Brown in his rebuttal testimony disagreed with the recommendations of TASC witness Hornby and NCSEA witness Beach, noting that the transmission loss calculations from the PNNL study are only based on four power flow snapshots. Witness Brown noted that the study states: "analysis over a long period of time (preferably one year or more) is needed to get a reliable assessment of total loss reduction." Therefore, witness Brown testified that he does not believe that the results of this limited study are appropriate for inclusion in avoided cost calculations at this time, and that there may be other factors that must be considered.

DISCUSSION AND CONCLUSIONS

The Commission agrees that integration of solar resources into a utility's generation mix results in both costs and benefits, many of which may be appropriate for inclusion in a utility's avoided cost calculations. The avoided costs associated with the energy and capacity produced by QFs have already been discussed and are generally applicable to all QFs. Solar QFs, however, may require the consideration of additional factors, such as the potential for avoided and deferred capacity costs for transmission and distribution systems, avoided transmission and distribution line losses, ancillary services and grid support. The Commission is aware that several studies regarding, and methods to calculate these costs and benefits, are currently under development. For example, the Electric Power Research Institute is set to release a study, titled The Integrated Grid – Phase II: Development of a Benefit Cost Framework, in the coming months. In light of these developments and the potential for significant amounts of solar generation to be constructed in North Carolina in the next few years, the Commission determines that It is premature for DEC, DEP and DNCP to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates.

To date, a comprehensive evaluation of solar integration costs in North Carolina has not been undertaken. The Commission agrees with EDF witness Munns that it should not rely on conclusions derived from limited observations or speculation to definitively establish the parameters of what should be included in avoided cost rates. The PNNL study included as Exhibit 1 to DEC/DEP witness Snider's testimony provides a robust evaluation of several aspects of integrating increasing amounts of solar generation into the utility's generation portfolio, including the impacts of solar PV on ancillary services and generation production cost, as well as voltage and power flows, and a limited evaluation of avoided losses in the transmission and distribution systems. The study points out, however, that it was limited in scope in order "to produce results in a timely manner using available data and analytic tools, to identify areas of concern, measure the degree of impact, and provide guidance for further actions. As a result, the study was limited to energy production cost modeling and steady-state power flow simulations. Potential PV impacts on dynamic system characteristics, such as frequency response and dynamic and transient stabilities, were not included the study scope.

Further, the PNNL study contains a conclusion that further studies are warranted in the sections related to generation, transmission, and distribution. Nonetheless, DEC and DEP propose at this time to include only the costs associated with generation-related ancillary services due to the intermittency of solar, despite the potential for benefits indicated in their transmission snapshot analysis and their distribution modeling.

The penetration rates of solar in DEC and DEP's service territories are not yet at the level at which integration costs reach the lowest thresholds evaluated by the PNNL study. As a result, the Commission concludes that it is premature to apply any selected findings that can be derived from the study. Once all aspects of solar integration are more fully evaluated, the costs proposed to be included now by DEC and DEP, those associated with ancillary services due to the intermittency of solar, may be offset completely or in part by some of the benefits that may be realized. In any event, future developments may provide a better idea of the total costs and benefits of integration and such costs and benefits can be more fully understood.

The Commission finds that, while ultimately it may be appropriate for DEC, DEP and DNCP to include the costs and benefits related to solar integration in their avoided cost calculations, such inclusion will be appropriate only when both the costs and benefits have been sufficiently evaluated and reviewed by the Commission so that a reasonable level of accuracy has been attained. Accordingly, the Commission concludes that it is premature for DEC, DEP and DNCP to include integration costs and benefits associated with increasing levels of solar integration in their service territories in the calculation of their avoided cost rates. The Commission further concludes that it is appropriate for the utilities to continue to apply their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence for this finding of fact is found in the testimony of DEC/DEP witness Snider, the testimony of NCSEA witness Beach, the testimony of SACE witness Rábago and the testimony of TASC witness Hornby.

NCSEA witness Beach argued that the energy credits attributed to solar QFs should be calculated with more granularity to better capture the energy value that solar QFs deliver. Witness Beach maintained that such an approach would allow solar QFs to receive higher energy payments for producing power during higher value, daytime off-peak hours. To support his position, witness Beach cited the Crossborder Study, which he argued showed that the output of a typical solar resource had more avoided energy value than a flat 24x7 block of power. Witness Beach claimed that this showed that the energy payments to solar QFs, which are based on the utilities' average on-peak and off-peak avoided energy costs, should be higher.

SACE witness Rábago and TASC witness Hornby testified that they supported witness Beach's proposal on this matter.

In his rebuttal testimony, DEC/DEP witness Snider refuted witness Beach's analysis. Witness Snider noted that witness Beach had only shown that, on an energy basis, typical solar output may have more value than a flat block of base load energy. He stated that witness Beach had failed to consider, however, the reduced energy benefits associated with the intermittent nature of solar generation. Further, witness Snider noted his concern regarding proposals that are designed to optimize the economic results for specific types of QFs. He argued that witness Beach had applied only beneficial aspects of solar generation as the basis to support a proposed solar-specific energy rate without any consideration of the costs associated with solar ramping and intermittency. Witness Snider concluded that such a proposal would unfairly burden customers with additional costs.

DISCUSSION AND CONCLUSIONS

Regardless of whether there is merit to witness Beach's observation that solar QFs may have more energy value than a flat, base load block of energy, the Commission declines to accept witness Beach's proposal to provide a definition of off-peak hours to suit the load profile of the typical solar QF based on the evidence in this record. As witness Snider rightly points out, witness Beach's proposal isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources. The Commission finds it difficult to square such an unbalanced approach with PURPA. Accordingly, the Commission declines to approve witness Beach's proposal to require a definition of off-peak hours to suit the load profile of solar QFs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29-30

The evidence supporting these findings of fact is found in the testimony of DNCP witness Williams, the testimony of NCSEA witness Cohen and the testimony of Public Staff witness Ellis.

DNCP witness Williams testified that the Commission established that the legally enforceable obligation (LEO) occurs when the QF has (1) obtained a CPCN (or filed a Report of Proposed Construction (ROPC), if applicable) and (2) indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output to that utility. Witness Williams further testified that DNCP believes that the standard is still too vague to be implemented in a fair manner, particularly with regard to the second prong of the test, as there is not enough guidance regarding what it means for a QF to "commit itself to sell its output." In order to clarify this standard, he stated that DNCP proposes to provide a simple form, to be completed by a QF seeking to sell its output to DNCP, that states that the QF has filed for or received a CPCN from the Commission (or has submitted a ROPC if it falls within the exception to the CPCN obligation), that it is making an offer to sell all of its output to DNCP for a period of at least two years, and that it agrees that a particular date is the date of the LEO. He stated that under current circumstances it is difficult to determine the point in time at which the commitment occurs.

With regard to how much time a QF is currently permitted to achieve commercial operations, DNCP witness Williams testified that DNCP advocates two changes. First, requiring a QF to have established a documented LEO and executed a PPA in advance of DNCP's subsequent rate filing; and, secondly, requiring QF commitment to achieve commercial operations by the later of (1) 30 months from DNCP's previous rate filing, (2) 18 months from the date the Commission approves the rates in the pending biennial period. Regarding the first point, he testified that it is reasonable to require a level of commitment to the then-current rates if a QF wants to remain eligible for them. Requiring a QF to establish a LEO, and to promptly execute a PPA, would preclude eligibility for in subsequent biennial rates, removing any ability for "cherry picking" rates between biennial periods. Regarding the second proposed change, he stated that the provision in the current standard QF contract that allows a QF up to 30 months to construct its facility is unnecessary for experienced solar developers, provides access to rates that may no longer reflect expected avoided costs, and adds significant uncertainty to the utility's resource planning. He recommended that the Commission reduce the development timeline as stated above.

NCSEA witness Cohen testified that DNCP filed this proposal just after the Commission approved the 30-month timeline in its Order issued February 21, 2014. He further testified that rates that have been proposed by a utility but not yet approved by the Commission do not provide an investor with sufficient certainty as to return on investment. According to witness Cohen, it therefore is difficult to secure financing for a project for which final rates are not available. He stated that, therefore, under DNCP's proposal, a developer would only have 18 months to develop a project to commercial operation, never 30 months. He further stated that while construction can be completed fairly quickly, although not as quickly as DNCP witness Williams suggested, construction is only part of the development process. The interconnection process in particular adds a significant amount of time to the development process.

Public Staff witness Ellis testified that it is not appropriate to retract the 30-month timeframe for completion of construction as proposed by DNCP witnesses Williams, noting that the Commission issued its Order approving this 30-month requirement on February 21, 2014, in the Sub 136 proceeding. He further testified that the Public Staff believes that this approach is the best means to resolve a number of competing issues that were raised in the Sub 136 proceeding and, at a minimum, it is premature to reconsider it at this point in time.

<u>DISCUSSION AND CONCLUSION</u>

With respect to DNCP's proposal to provide a simple form, to be completed by a QF seeking to sell its output to DNCP, in order to establish that a particular date is the date of the LEO, no party expressed any opposition to it, but neither did any party express any support. The Commission is inclined to move toward such an approach, but requests that parties address it in the upcoming phase two of this proceeding. Details, including, but not limited to, the following, should be addressed: how the QF would know it needed to obtain the form, how it would obtain it (e.g., from a specified place on a utility's website), whether or how it could be submitted electronically, and the extent to which the utility could change or withdraw the form without prior Commission approval.

As to DCNP's position that a QF should have to have executed a PPA in advance of DNCP's subsequent rate filing in order to be eligible for the approved avoided cost rates, the

Commission, notes that it rejected the execution of contracts as being the trigger point in its order establishing avoided cost rates in the Sub 136 proceeding because the utilities have the ability to delay the execution of contracts with QFs. With recently-approved 30-month timeframe for completion of construction, the Commission agrees with the Public Staff that it is premature to retract it at this time, given that it was approved shortly before the Commission issued the order initiating this proceeding. It is still the best means of resolving a number of competing issues that were raised in the Sub 136 proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The Commission in the Sub 136 proceeding concluded that each QF that (a) has obtained a CPCN or filed an ROPC, as applicable, no later than November 1 of the year in which a biennial proceeding has been initiated, or the actual filing date of proposed rates if later, and (b) has indicated to the relevant North Carolina utility that it is seeking to commit itself to sell its output should be entitled to the fixed, long-term avoided costs rates approved in the immediately preceding biennial proceeding. The Commission is aware that the tariffs of the utilities may state November 1, 2014, without the proviso that the date of the actual filing, if later, controls. To the extent the tariffs state November 1, 2014, they shall be considered amended to include the language "or the actual filing date of proposed rates if later." It is appropriate that the currently approved avoided cost rates and tariffs remain available until 60 days from the date of this Order, which is the date the utilities are required to file new proposed avoided cost rates in compliance with this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP and DNCP shall file proposed avoided cost rates in compliance with this Order, and in compliance with the Commission's Order establishing avoided cost rates in the Sub 136 proceeding to the extent not superseded by this Order, 60 days from the date of this Order.

2. That the currently approved avoided cost rates and tariffs shall remain available until the utilities file new proposed avoided cost rates in compliance with this Order.

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

4. That the proposed avoided cost rates to be filed in compliance with this Order shall include a standard five-year levelized rate option for all other QFs contracting to sell three MW or less capacity.

5. That DEC, DEP and DNCP shall continue to use the peaker method to calculate avoided cost rates, as discussed more specifically herein, without the subtraction of energy benefits associated with a new CT proposed by DNCP, without the cap on production cost savings proposed by DEC and DEP, and without the inclusion of zeroes in any years, all of which would produce rates that are lower than full avoided costs.

6. That, in the calculation of the installed cost a CT, DEC, DEP and DNCP shall use data from publicly available industry sources and tailor it only to the extent clearly needed to adapt any such information to the Carolinas and Virginia.

7. That, in the calculation of the installed cost a CT, DEC, DEP and DNCP shall include transmission interconnection costs (but not network upgrade costs), equipment and construction costs with a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, a reasonable estimate of useful life of a CT, the cost of land for a greenfield site, and economies of scale for up to four CTs constructed on the same site. DEC, DEP and DNCP shall not include any economies of scope associated with the construction of more than one CT at the same time.

8. That the generation expansion plans used in the avoided cost production cost models for the purpose of calculating avoided energy rates shall be based on IRP expansion plans that take into account only known and quantifiable costs.

9. That DEC, DEP and DNCP shall calculate and include the fuel hedging benefits associated with purchases of renewable energy, as discussed in this Order, in the avoided energy component of its avoided cost rates to be filed in phase two of this proceeding.

10. That avoided capacity payments shall continue to be based on a per-kWh capacity payment.

11. That DEC, DEP and DNCP shall continue to calculate and include in their avoided cost rate schedules an Option B, with avoided capacity rates calculated using the same on-peak hours (for both summer months and non-summer months) agreed to in the Settlement Agreements entered into among DEC, DEP, DNCP and the Public Staff in the Sub 136 proceeding.

12. DEC, DEP and DNCP shall continue to offer an Option A set of avoided capacity rates and both Option A and Option B capacity rates shall be filed for approval by the Commission in phase two of this proceeding.

13. That a PAF of 1.2 shall be utilized by DEC, DEP and DNCP (for its Schedule 19-FP) in their avoided cost calculations for QFs except hydroelectric facilities with no storage capability and no other type of generation.

14. That a PAF of 2.0 shall be utilized by DEC, DEP and DNCP (for its Schedule 19-F) in their respective avoided cost calculations for hydroelectric QFs with no storage capability and no other type of generation until discontinued in accordance with the stipulation filed by DEC, DEP and the NC Hydro Group.

15. That DEC, DEP and DNCP shall not incorporate the costs and benefits related to solar integration in their avoided cost calculations until such time that future studies and developments have further clarified have been concluded and the Commission has approved such inclusions.

16. That until such time as the studies are concluded and Commission authorization given, the utilities shall continue to follow their previously approved adjustments for line losses based on whether the facilities interconnect at the distribution level or transmission level.

17. That DNCP's proposal for a simple form to be used to determine the date of the commitment of a QF, along with how it should be implemented shall be approved with the details and implementation to be considered in the next phase of this proceeding and the parties are directed to address it in their filings.

18. That the 30-month timeframe for completion of construction approved in the Sub 136 proceeding shall not be changed.

19. That WCU and New River shall file proposed avoided cost rates as directed by the Commission in the Sub 136 proceeding, except as otherwise modified in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. P-100, SUB 133C

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Time Warner Cable Information	)	
Services (North Carolina), LLC, for Designation	)	ORDER ON JURISDICTION
As An Eligible Telecommunications Carrier	)	

HEARD: Friday, October 11, 2013, at 10:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, Commissioners Bryan E. Beatty, Susan W. Rabon, ToNola D. Brown-Bland, Don M. Bailey, and James G. Patterson

APPEARANCES:

For Time Warner Cable Information Services (North Carolina), LLC:

Marcus W. Trathen and Timothy G. Nelson, Brooks, Pierce, McLendon, Humphrey & Leonard, LLP, 150 Fayetteville Street, Suite 1600, Raleigh, North Carolina 27601

For North Carolina Telephone Cooperative Coalition and Telephone Membership Corporations:

Dwight Allen, Allen Law Offices, PLLC, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27615

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the North Carolina Rural Electrification Authority:

Lareena J. Phillips, State of North Carolina Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27602

BY THE COMMISSION: On July 23, 2013, Time Warner Cable Information Services (North Carolina), LLC (TWCIS (NC)), pursuant to Section 214(e)(2) of the federal Communications Act of 1934, as amended (Communications Act), Section 54.101 et seq. of the rules of the Federal Communications Commission (FCC) and the rules and regulations of the North Carolina Utilities Commission (the Commission), filed an Application for Designation as an Eligible Telecommunications Carrier (ETC) and Request for Expedited Ruling Regarding ETC Designation in Telephone Membership Corporation (TMC) Service Areas (Application). In the Application, TWCIS (NC) explained that it was seeking Commission designation as an ETC "in order to receive Lifeline support (but not 'high cost' support) from the federal universal service fund (USF) for the benefit of low-income customers." Application pp. 4-5. TWCIS (NC) further explained that it was seeking ETC designation throughout its network footprint[1] which includes portions of the rural study areas of various TMCs. TWCIS (NC) thereafter requested that the Commission grant its application for ETC designation throughout its network footprint.

On July 30, 2013, the Commission issued an Order Requesting Comments from the Public Staff and other parties to this docket regarding TWCIS (NC)'s contentions that the Commission has authority to make an ETC designation in TMC study areas and/or that the FCC is the appropriate agency to make such a designation "[if] the Commission elect[s] to move forward in this proceeding as to only certain portions of TWCIS (NC)'s proposed service area …." TWCIS (NC) Reply Comments, p. 2.

On August 7, 2013, the North Carolina Rural Electrification Authority (NCREA) filed a petition to intervene pursuant to Commission Rule R1-19 and a Motion for Extension of Time to File Comments. On August 9, 2013, the Commission issued an Order Granting Petition to Intervene and Motion for Extension of Time to File Comments. In that Order, the Commission permitted the NCREA to intervene and extended the time of the parties to file comments from August 9, 2013, to August 23, 2013, and reply comments from August 19, 2013, until September 3, 2013.

On August 23, 2013, the Public Staff, the NCREA and the North Carolina TMCs[2] filed comments. On September 3, 2013, TWCIS (NC) filed reply comments. The parties' comments are briefly summarized below.

On September 23, 2013, the Commission issued an Order scheduling an oral argument for October 11, 2013, on TWCIS (NC)'s contentions that the Commission has authority to make an ETC designation in TMC study areas and/or that the FCC is the appropriate forum to make such a designation "[if] the Commission elect[s] to move forward in this proceeding as to only certain portions of TWCIS (NC)'s proposed service area …."

The Oral Argument was held as scheduled on October 11, 2013.

[1] In North Carolina, TWCIS (NC)'s network footprint includes portions of the rural study areas of Windstream North Carolina; Windstream Concord Telephone; Windstream Lexcom Communications; Mebtel, d/b/a Centurylink; Carolina Telephone and Telegraph Company, d/b/a Centurylink; Central Telephone Company of North Carolina, d/b/a Centurylink; North State Telephone Co., d/b/a North State Communications and Pineville Telephone Company. In addition, TWCIS (NC)'s service area includes portions of the rural study areas of the following TMCs: Atlantic, Randolph, Star, Surry and Yadkin Valley.

[2] The TMCs consist of Atlantic Telephone Membership Corporation, Randolph Telephone Membership Corporation, Skyline Telephone Membership Corporation, Star Telephone Membership Corporation, Surry Telephone Membership Corporation, Tri-County Telephone Membership Corporation, Wilkes Telephone Membership Corporation and the Yadkin Valley Telephone Membership Corporation.

POSITIONS OF THE PARTIES

Public Staff

The Public Staff noted that in its Order Requesting Comments, the Commission cited two prior rulings by the Commission which addressed the authority of the Commission over issues involving ETC designation in rural areas served by TMCs. In both cases, the Commission held that the NCREA was the appropriate "State commission" to render judgment on ETC issues involving TMCs. The Public Staff asserts that, when properly construed, these decisions and several statutes in the Public Utilities Act strongly suggest that the NCREA is the proper agency to decide whether a competing local provider (CLP) such as TWCIS (NC) should be designated as an ETC in a TMC service area.

In its underlying analysis, the Public Staff acknowledged that TWCIS (NC) was correct in its assertion that the facts in TWCIS (NC)'s current case are different from the facts that were presented to the Commission in the prior cases. Specifically, the Public Staff noted that in this case, TWCIS (NC), a Commission-regulated CLP, rather than an unregulated cellular carrier, is requesting an ETC determination from this Commission for service in rural areas also being served by TMCs. The Public Staff also noted that in this case, unlike the prior Commission cases, TWCIS (NC) was not seeking to redefine a rural study area of a TMC.

In the Public Staff's opinion, however, the aforementioned factual distinctions bore no relation to the rationale underlying those decisions. According to the Public Staff, the more critical factor in those decisions was the Commission's determination that it had no regulatory jurisdiction over TMCs and that it should not take any regulatory action that would have affected TMCs. According to the Public Staff, those same justifications exist in this case and support its conclusion that the NCREA is the appropriate "State commission" to render judgment on TWCIS (NC)'s request to be designated as an ETC in the service areas of various TMCs.

Additionally, the Public Staff observed that the Public Utilities Act supports the same conclusion. For instance, the Public Staff noted that G.S. 62-110(f3) states: "The provisions of subsection (f1) of this section shall not be applicable to areas served by telephone membership corporations …." North Carolina General Statutes Section 62-110(f1) is the statute giving the Commission authority to allow CLPs to operate in areas of North Carolina without regard to whether local telephone service is already being provided. According to the Public Staff, the effect of G.S. 62-110(f3) is to exclude the areas served by TMCs from the areas in which the Commission may grant TWCIS (NC) authority to operate. This same language precludes the Commission from authorizing TWCIS (NC) or any other Commission regulated carrier from providing Lifeline service, or any other service in a TMC area. Therefore, in the opinion of the Public Staff, the Commission cannot make an ETC designation in a rural area served by a TMC because of this prohibition.

TMCs

Briefly summarized, the TMCs' positions are as follows: (1) The Commission lacks statutory authority to designate TWCIS (NC) as an ETC in TMC service areas; (2) the NCREA is the proper "State commission" to make ETC designations in areas served by TMCs; and (3) the

Commission should deny the request of TWCIS (NC) to designate TWCIS (NC) as an ETC in areas served by TMCs or refer the matter to the NCREA.

In support of these positions, the TMCs noted that regulation of telephone service in North Carolina is somewhat unique in that the General Assembly has created a bifurcated regulatory system for telecommunications service providers. According to the TMCs, it is clear that the Commission regulates telecommunications services provided by public utilities and the NCREA regulates telecommunications services provided by TMCs. Because this issue affects the service areas of TMCs and therefore potentially the service of TMCs, the TMCs argue that this question should be therefore determined by the NCREA. According to the TMCs, the decisions of the Commission cited in the Comments Order support the TMCs' position. Finally, the TMCs also note that Time Warner has previously acknowledged that the NCREA is the relevant "State commission" in North Carolina with respect to other issues involving TMCs that also arise under the Telecommunications Act of 1996 (the Act) in Time Warner's Preemption Petition filed with the FCC.

NCREA

NCREA noted that pursuant to federal and State laws, TMCs are engaged in the business of intrastate telecommunications services in certain defined rural areas of North Carolina. Pursuant to 47 U.S.C. 214(e)(2), a "State commission" is authorized to designate a common carrier as an ETC for a service area designated by a State commission. In addition, 47 U.S.C. 153(48) defines a "State commission" as "the commission, board or official (by whatever name designated) which under the laws of any State has regulatory jurisdiction with respect to the intrastate operations of carriers."

Under North Carolina law, the NCREA is the State agency that has direct jurisdiction over TMCs and the NCREA has jurisdiction over intrastate operations of carriers in rural study areas served by TMCs. See G.S. 117-1 et seq. Therefore, according to the NCREA, the NCREA is the State agency responsible for making ETC designations in rural study areas served by TMCs. For those reasons, TWCIS (NC)'s request for an expedited ruling regarding ETC designation in TMC service areas should be referred by this Commission to the NCREA for disposition.

The NCREA also argues that additional support for its position that it is the "State commission" responsible for designating ETCs in areas served by TMCs is found in the Public Utilities Act. Specifically, the NCREA cites to G.S. 62-110(f5) and (f6). According to the NCREA, those statutes recognize the division of responsibilities between the Commission and the NCREA based upon the service area of the carrier for ETC certification purposes. Accordingly, the NCREA believes that those statutes suggest that the NCREA and not the Commission has jurisdiction to entertain TWCIS (NC)'s request for ETC designation in rural areas served by TMCs.

TWCIS (NC)

TWCIS (NC) argues that the starting point for any analysis regarding its request for the Commission to designate it as an ETC in certain areas served by TMCs is controlling federal law. Under the federal telecommunications law, a state commission is authorized to designate a common carrier meeting the requirements of the statute as an ETC for a service area designated by the State commission. 47 U.S.C. 214(e)(2). According to TWCIS (NC), controlling federal law and regulations indicate that the State agency with regulatory authority over TWCIS (NC), as established by State law, is the relevant commission for the purposes of its ETC designation request. TWCIS (NC) asserts that under State law, the Commission has regulatory authority over TWCIS (NC) and the NCREA does not. Therefore, reasons TWCIS (NC), the Public Utilities Act and federal law and regulations, when properly construed, clearly provide that the Commission, and not the NCREA, is the only State entity with the appropriate regulatory authority to address TWCIS (NC)'s Petition for an ETC designation in areas served by TMCs.[1]

According to TWCIS (NC), the commenting parties' reliance on two prior Commission decisions as support for a Commission decision to defer to the jurisdiction of the NCREA runs contrary to the FCC's Forbearance Order and is flawed because the request in this case is factually distinguishable from those decisions. Further, TWCIS (NC) asserts that it would be forced to seek relief from the FCC under 47 U.S.C. 214(e)(6) if the Commission defers to the jurisdiction of the NCREA and refuses to fully implement the service area proposed by TWCIS (NC) including the areas served by TMCs.

DISCUSSION

TWCIS (NC) seeks designation as an ETC to be able to receive Lifeline support from the federal USF pursuant to Section 214(e)(2) of the Communications Act, as amended, Section 54.101 et seq. of the rules of the FCC, and the rules and regulations of this Commission. At issue at this time is this Commission's authority to designate TWCIS (NC) as a Lifeline-only ETC in certain portions of TMC study areas. TWCIS (NC) represents that it has authority to serve subscribers within local exchange carrier (LEC) study area boundaries pursuant to Section 214(e)(5) of the Communications Act without modification of any LEC study area boundaries because the FCC recently granted forbearance from requirements that carriers request modification of such LEC study area boundaries when seeking Lifeline-only ETC designation. See Time Warner Cable Petition for Forbearance, Memorandum Opinion and Order, WL Docket No. 09-197, FCC 13-44, ¶ 8 (rel. April 15, 2013). TWCIS (NC) requests a ruling that this Commission is the appropriate "State commission" to address its request for Lifeline-only ETC designation within the TMC study area boundaries where TWCIS (NC) is authorized to serve.[2] The NCREA, the Public Staff, and the TMCs have intervened and contend that the NCREA is the appropriate "State commission" to address TWCIS (NC)'s petition with respect to TMC study area boundaries.

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[1] In its reply comments, TWCIS (NC) asserts that the NCREA is the relevant "State commission" for implementing the telecommunications provisions of the federal Act when it seeks to compel TMCs to interconnect with its network and/or to arbitrate unresolved interconnection disputes between TMCs and TWCIS (NC), even though the NCREA lacks regulatory jurisdiction over the operations of TWCIS (NC) under State law. TWCIS (NC) explains that the NCREA is the relevant "State commission" in that situation because the NCREA has underlying jurisdiction under State law over the TMCs and the TMCs, as incumbent local exchange companies under federal law, have a duty to interconnect and arbitrate interconnection agreements with TWCIS (NC).

[2] No question exists with respect to this Commission's authority to address TWCIS (NC)'s request in non-TMC areas, the vast majority (as much as 97 percent) of the areas where TWCIS (NC) seeks Lifeline-only ETC designation.

To resolve this dispute, the Commission first sets forth the pertinent statutes that control its discussion in this matter. Section 214(e)(2) of the Communications Act states, in pertinent part:

> A State commission shall upon its own motion or upon request designate a common carrier that meets the requirements of paragraph (1) as an eligible telecommunications carrier for a service area designated by the State commission.

47 U.S.C. 214(e)(2). "State commission" is defined in the Communications Act as:

> the commission, board, or official (by whatever name designated) which under the laws of any State has regulatory jurisdiction with respect to intrastate operations of carriers.

47 U.S.C. 153 (48). "Common carrier" or "carrier" is defined in the Communications Act as:

> any person engaged as a common carrier for hire, in interstate or foreign communication by wire or radio or interstate or foreign radio transmission of energy.

47 U.S.C. 153 (11). Under North Carolina law "public utility" is defined as a person:

> conveying or transmitting messages or communications by telephone or telegraph, or any other means of transmission, where such service is offered to the public for compensation.

G.S. 62-3(23)(a)(6). Pursuant to G.S. 62-3(23)(d), TMCs are not "public utilities" except as otherwise expressly provided in Chapter 62.

TWCIS (NC) alleges that it has a right to serve subscribers in TMC study areas. TWCIS (NC) has a certificate of public convenience and necessity (CPCN) as a CLP from this Commission to provide public utility service in this State. TWCIS (NC) is an investor-owned corporation providing telecommunications services as a common carrier to the public for compensation. Although G.S. 62-110(f3) prohibits this Commission from granting a CLP a CPCN to serve within a TMC service area, TWCIS (NC) contends that the provisions of the Telecommunications Act of 1996 and the FCC Forbearance Order create, in limited respects, this right by operation of federal law. None of the three intervenors has challenged TWCIS (NC)'s right to serve within a TMC service area.

The issue, then, is whether this Commission, the NCREA, or the FCC is the appropriate agency to address TWCIS (NC)'s request for Lifeline-only ETC designation in TMC study areas as permitted by federal law. None of the parties advocates that the FCC is the appropriate agency; each advocates that one of the two State agencies should make the designation. TWCIS (NC) argues that no North Carolina statute conveys jurisdiction to the NCREA to address its request, while G.S. 62-3(23)(a)(6) and G.S. 62-30, do provide jurisdiction to this Commission to address it. The Commission agrees.

At oral argument, the three Intervenors were requested repeatedly to cite a statute establishing NCREA jurisdiction to address TWCIS (NC)'s request. They were unable to do so.

Intervenors argue that TMCs have defined service area boundaries, that the NCREA is the regulatory authority over TMCs and the TMC study areas, and that, consequently, the NCREA is the "State commission" with authority to make the ETC designation for TWCIS (NC) in the TMC study area. They argue that, as the NCREA has jurisdiction over a geographic area served by TMCs, the NCREA likewise has jurisdiction over a CLP serving there. The Commission disagrees.

This Commission, as an agency of the State created by the General Assembly, has no authority, express or otherwise, except that given to it by statute. State ex rel. Utilities Comm'n v. Mountain Elec. Coop., 108 N.C. App. 283 (1992), aff'd, per curiam, 334 N.C. 681 (1993). State ex rel. Utilities Comm'n v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977). The same rule applies to the NCREA, as it, too, is a legislatively created State agency.

Unable to cite a statute conveying NCREA express jurisdiction, the intervenors were forced to rely upon the concept of ancillary jurisdiction. The Commission finds no authority for reliance on ancillary jurisdiction in this context. Ancillary jurisdiction is a judicial postulate giving federal courts jurisdiction over matters normally outside of their subject matter jurisdiction if they are found ancillary or related to the primary matters of a case that is within the court's jurisdiction.[1] The intervenors cite no authority for the proposition that ancillary jurisdiction gives the NCREA jurisdiction here. No mention is made of ancillary jurisdiction in the written pleadings. This concept was first mentioned in oral argument. In fact, the purpose of ancillary jurisdiction is to avoid fragmented authority over matters where a primary action is properly before the federal court. Here, there is no question that this Commission is the appropriate "State commission" to make the ETC determination for 97 percent of TWCIS (NC)'s eligible subscribers. Intervenors would have this Commission make the ETC designation for the 97percent, but require the NCREA

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[1] Ancillary jurisdiction has been addressed in several federal and state cases, however, not in the manner as it has been asserted by the Intervenors. For example in Morrow v. District of Columbia, 417 F.2d 728, 740 (D.C. Cir. 1969), the D.C. Circuit states:

> Ancillary matters have been broadly defined as matters 'auxiliary, accessorial or subordinate' to the main matter. Glens Falls Indemnity Co. v. United States, 9 Cir., 229 F.2d 370, 373-374 (1956). The overriding concern of the courts has been to insure that 'complete justice may be done.' State of Iowa v. Union Asphalt & Roadoils, Inc., S.D.Iowa, 281 F.Supp. 391, 396 (1968). The Union Asphalt case involved a petition for payment of attorney fees. The court, in ordering the fees to be paid, stated:
>
>> The ancillary jurisdiction theory is relatively simple— once federal jurisdiction properly attaches to a primary case, the court also has jurisdiction over certain subsidiary or subordinate disputes even though it might not independently be able to proceed to adjudicate them
>
> …To effectuate these purposes, and yet confine a court to proper bounds consistent with the past use of ancillary jurisdiction as discussed above, we believe that, in a situation such as the one before us, ancillary jurisdiction should attach where: (1) the ancillary matter arises from the same transaction which was the basis of the main proceeding, or arises during the course of the main matter, or is an integral part of the main matter; (2) the ancillary matter can be determined without a substantial new fact-finding proceeding; (3) determination of the ancillary matter through an ancillary order would not deprive a party of a substantial procedural or substantive right; and (4) the ancillary matter must be settled to protect the integrity of the main proceeding or to insure that the disposition in the main proceeding will not be frustrated.

See also Artis v. Artis, 228 N.C. 754, 764, 47 S.E.2d 228, 234 (1948) ("when the Superior Court once acquires jurisdiction of a case, it will administer all necessary incidental matters connected with the litigation").

to make the designation for the rest, leaving the possibility for approval for some and disapproval for others, even where next door neighbors might receive conflicting rulings. Were the concept of ancillary jurisdiction to apply, it would support TWCIS (NC)'s argument that there should not be two "State commissions" making the ETC determination, but one – this Commission, where it is undisputed that jurisdiction over the vast majority of the request lies.

If the issue before the Commission was whether as a CLP, and pursuant to its CPCN, TWCIS (NC) possesses authority to serve subscribers (both those eligible for Lifeline support and those ineligible) in a TMC study area, perhaps the Intervenor arguments would have greater merit. However, Intervenors do not contest the right of TWCIS (NC) to provide CLP service in these areas.[1] Consequently, the argument that the NCREA, as the "State commission" over an area for some purposes, has jurisdiction over a CLP so as to entertain an application for ETC designation for Lifeline-only subsidy falls short. The NCREA cannot deny TWCIS (NC) the right to serve in the study areas, so it follows that the NCREA lacks jurisdiction to address terms of service such as Lifeline-only ETC eligibility for a common carrier public utility, which is not a member-owned TMC.

Intervenors cite G.S. 62-110(f3), passed in 1995 before Congress authorized CLPs to compete in TMC study areas, which limits the Commission's authority to issue a CPCN to a CLP to provide service within a TMC study area boundary. They argue that, as the Commission cannot authorize such service, even if the CLP obtains its authorization through operation of federal law, G.S. 62-110(f3) precludes the Commission from exercising any authority over the CLP's operations within the TMC study area. The Commission disagrees. The nature of the service provider and the nature of the service provided are the determinative factors in establishing the existence of this Commission's jurisdiction, not the issuance of a CPCN. This conclusion is firmly established by North Carolina case law in closely analgous situations.

Persons providing services falling within the statutory definition of public utilities have been adjudged subject to the Commission's jurisdiction even though operating without a duly authorized CPCN from the Commission. The factual circumstance has been where a person has provided water or wastewater service to the public for compensation without first seeking or obtaining the required CPCN. The North Carolina Court of Appeals has ruled unequivocally on more than one occasion that the absence of the CPCN is no impediment to the authority of the Commission to exercise jurisdiction over the rates or services of the public utility and even to order refunds for the unauthorized collection of public utility revenues.

> The status of an entity as a public utility, entitled to the rights conferred by the statutes and <u>subject to the jurisdiction of the Commission</u>, does not depend upon whether it has secured a certificate of public convenience and necessity, pursuant to G.S. 62-110, but is determined instead according to whether it is, in fact, operating a business defined by the Legislature as a public utility. <u>Utilities Commission v. Carolina Telephone and Telegraph Co.</u>, 267 N.C. 257, 148 S.E.2d 100 (1966). If an entity is, in fact, operating as a public utility, it is subject to the

[1] Counsel for the Public Staff stated at oral argument "I think that was before CLPs entered the picture. As I understand it, under the FCC rulings, the CLPs have the right to serve anywhere even in TMC service areas." Tr. p. 81, ll. 6-14.

> regulatory powers of the Commission notwithstanding the fact that it has failed to comply with G.S. 62-110 before beginning its operation.

State ex rel. Utilities Comm'n v. Mackie, 79 N.C.App. 19, 32, 338 S.E.2d 888, 897 (1986) (emphasis added). See also State ex rel. Utilities Com'n v. Buck Island, Inc., 162 N.C.App. 568, 592 S.E.2d 244 (2004).

If a provider operating within the State on a completely ultra vires basis and without a CPCN is subject to the Commission's jurisdiction because it is operating a business defined by the Legislature as a public utility, a person like TWCIS (NC) operating within the State pursuant to federal law most assuredly is subject to the Commission's jurisdiction. The FCC, operating pursuant to such federal law, has delegated to the State commission with regulatory jurisdiction under the laws of the state with respect to intrastate operations of carriers the right to make the ETC designation. This Commission has such jurisdiction over TWCIS (NC)'s operations and possesses such jurisdiction whether TWCIS (NC) has a CPCN or not.

The Commission determines that the provisions of G.S. 62-110(f3) do not prevent the Commission from designating TWCIS (NC) as an ETC within TMC boundaries. In Docket No. P-1262, Subs 0 and 1, the Commission granted TWCIS (NC) a CPCN to provide intrastate interexchange service and a CPCN to provide intrastate local exchange and exchange access service by Order dated July 24, 2003. The CPCN granted in Docket No. P-1262, Sub 1 authorizes TWCIS (NC) to provide "intrastate local exchange and exchange access service as a Competing Local Provider in the state of North Carolina." In its Order the Commission stated:

> The sole issue in these dockets is whether TWC has met the criteria for certification. The Commission concludes that it has. As TWC has stated many times, it is voluntarily submitting to the jurisdiction of this Commission with reference to local and long distance service, and it intends to provide these services in accordance with Commission rules and regulations.

The CPCN and the Commission's Order make no specific exceptions in reference to G.S. 62-110(f3) or otherwise with respect to TMC study areas. Except to the extent otherwise expressly preempted, TWCIS (NC) has, in fact, complied with its obligations and responsibilities undertaken upon certification.

As previously stated, no question is raised as to the authorization of TWCIS (NC) to serve within TMC study areas. All parties acknowledge that federal law authorizes this service. Sections 251(a) and (b) of the Communications Act impose duties on all local exchange carriers, including without reservation or qualification to TMCs. These duties include interconnection, resale, number portability, dialing parity, access to rights-of-way, and reciprocal compensation. On May 26, 2011, the FCC issued a Declaratory Ruling stating that a rural carrier's exemption under Section 251(f)(1) offers an exemption only from the requirements of Section 251(c) and does not relieve it of its obligations under Sections 251(a) or (b).

The FCC in its Forbearance Order of April 15, 2013, granted limited forbearance for all carriers seeking to provide Lifeline-only service from the requirements that the service area of an ETC conform to the service area of any local telephone company serving in the same area. As a result of this order, if a commission designates a carrier as a limited, Lifeline-only ETC in a part of a rural service area, that designation will not require re-definition of the rural telephone company's service area.

TWCIS (NC) has a right to serve within North Carolina pursuant to its July 24, 2003 CPCN. It has a right to serve within the TMC study area pursuant to the federal statutes and orders. In effect, the federal statutes and orders augment TWCIS (NC)'s authority under its CPCN[1] and supersede any limitations G.S. 62-110(f3) might otherwise have imposed on TWCIS (NC)'s service within TMC study area boundaries and, specifically, with respect to the authority of this Commission to designate TWCIS (NC) as an ETC for Lifeline-only subsidy eligibility.[2]

According to the Intervenors, the intent and purpose of G.S. 62-110(f3) is to shield TMCs from competitive telecommunications services within the boundaries of the TMC study areas. However, each intervenor readily concedes that TWCIS (NC) (and any other competitive telecommunications carrier, for that matter), as a result of federal laws subsequently passed by Congress and orders issued by the FCC, possesses authority freely to compete within the TMC study areas. Consequently, the relief Intervenors seek – to read G.S. 62-110(f3) to prevent this Commission from exercising authority to address TWCIS (NC)'s request for Lifeline-only ETC designation – is to rely upon the anticompetitive intent of the 1995 statute that in all other respects has been rendered a nullity.

Intervenors interpret G.S. 62-110(f3) as a prohibition against this Commission's granting TWCIS (NC) ETC designation for Lifeline subsidy when the granting of ETC status assists TWCIS (NC), which has authority to serve in the areas at issue, to compete on equal terms, which is in accord with the federal Act and FCC orders that authorize TWCIS (NC) to serve in the rural

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[1] Counsel for the Public Staff responded as follows at the oral argument to a question posed by the Commission:

Q. So would a CLP come to this Commission because it wanted to serve an area that was larger than just the TMC service area?

A. Well, yes. I think your question is would they come to this Commission for a certificate, rather than come to the REA for a certificate, and frankly, it's hard to even envision coming to the REA for a certificate to serve in TMC service areas without also getting the certificate from this Commission to serve in - - to serve in the rest of the state. And having a certificate from this Commission, I think they are able to serve in the state, as a whole, and I think that that is the result of the FCC's rules. Again, I'm not able to explain the interrelationships and say what FCC rule makes it clear that, having been certificated by this Commission, the CLP is entitled to serve throughout the state, but I understand that matter is what the FCC rules do provide.

Tr. p. 83, l. 24 - p. 84, l. 18.

[2] In the same legislation in which the General Assembly enacted G.S. 62-110(f3) in 1995, it also enacted G.S. 62-110(f2). Subsection (f2) likewise shields small, rural investor-owned public utility telecommunications companies from competition (i.e., those with access lines of 200,000 or less). The only conclusion to draw from this is that the General Assembly sought to shield selected small incumbent carriers from competition. The purpose was not, as Intervenors suggest, to shift regulatory control over CLPs from this Commission to the NCREA in TMC study areas or to create geographic areas in which investor-owned public utilities were eliminated from this Commission's jurisdiction. Subsection (f2) has been largely superseded by the same federal acts and orders as those that have superseded Subsection (f3).

areas at issue and which render G.S. 62-110(f3) for all other purposes null and void.[1] Subsection (f3) simply no longer exists as a vehicle to prevent or delay authorization for TWCIS (NC) Lifeline subsidy eligibility so as to compete in equal terms with the incumbent rural providers when in all other respects its anti-competitive prohibitions have been superseded.

Subsection (f3), to the extent it continues to have any enforceability whatsoever, by its terms only prevents the Commission from granting a competitive carrier a CPCN in a TMC study area. The statute clearly does not contemplate or anticipate the situation faced today where, as a result of the federal Communications Act and FCC orders, the competing carriers possess authority to serve in the rural areas in question with or without a State-issued CPCN. Intervenors would interpret G.S. 62-110(f3) as leaving the Commission powerless over any aspects of competitive service in the areas in question, even though the consequence of the absence of a CPCN otherwise is completely non-existent. The competitive carriers are free to compete.

This interpretation leads to an absurd result. Should the competing carrier engage in slamming or cramming, misdirected calls, fraud, or refusal to pay its wholesale carrier for wholesale service, under Intervenors' interpretation, the Commission is left powerless to exercise jurisdiction over an investor-owned public utility to rectify these otherwise proscribed practices. Intervenors can cite no statute authorizing the NCREA to regulate competing public utility carriers. Any argument they make suggesting lack of authority for the Commission to regulate CLPs in the rural areas in question applies with greater force against the NCREA. As a result, Intervenors argue for a framework that leaves the State powerless to regulate CLPs in TMC study areas.

An interpretation such as that advocated by Intervenors that federal law expands TWCIS (NC)'s right to serve within TMC study areas, while simultaneously leaving the State commission otherwise with exclusive authority over the carrier's rates and services powerless to exercise such authority there, makes no sense. When federal law eliminates rights to exclude competition within areas previously protected from such competition, while at the same time delegating to the "State commission" with jurisdiction over competing carriers the right to make ETC designations there, actions by the state to withhold the right of the "State commission" to make the designation would

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[1] Counsel for the TMCs argues at oral argument that "there are competitive end (sic) roads, and some of the laws in North Carolina appear to prohibit competition in rural areas, have pretty much been overruled by federal law. The rules are different, and so they do have CLPs, they do have wireless competitors, and they lost a lot of access lines." Tr. p. 28, ll.13-19.

Counsel for the TMCs further argued, "I think, under federal law, when the '96 Act was passed, it came after the '95 Act in North Carolina, the rules changed. So the CLPs that you were certifying, they are operating in TMC territory. They just are. And the rural companies have a right to protest that and say that you ought not to be there, but the standard under which they have to protest that, it shows that there is irreparable financial loss." Tr. p. 45, ll. 18 - p. 46, ll 2.

Lastly, Counsel for the TMCs responded as follows to a question posed by the Commission:

Q [W]hen this Commission granted Time Warner the CPCN, if you look at G.S. 62-110(f3), was it the case that that CPCN allowed Time Warner to provide service in the TMC area?

A. I think probably not, because you cannot, under state statutes, grant CLP authority in the TMC territory, but I think there are provisions of federal law that had changed that, and they are operating there.

Tr. p. 49, ll. 1-9.

be violative of the intent of Congress and the FCC and would serve no other legitimate state purpose.

TMCs are not subject to the Commission's jurisdiction because they are specifically excluded from the definition of public utility pursuant to G.S. 62-3(23)d. They do not provide service to the using and consuming public for compensation, as do public utilities, but only provide service to member owners. TMC membership sets its own rates and controls the level of service without need for the oversight of an economic regulator like this Commission. The members provide these functions themselves. TMCs operate on a cost-based basis. If revenues exceed costs, members receive a rebate. There are no profits to regulate. In the Commission's view, it is the nature of the service provider that controls the determination of the regulatory agency with jurisdiction to make Lifeline-only ETC determinations, not the location of the subscriber to whom service is provided. This Commission has regulatory jurisdiction with respect to the intrastate operations of TWCIS (NC) operating as a CLP.

Intervenors also rely upon other Subsections of G.S. 62-110 as support for an expression of legislative intent that the NCREA is the appropriate State agency to grant ETC designation for CLPs in TMC study areas. G.S. 62-110(f5) states, in part,:

> During the period that a telecommunications service provider is serving as a universal service provider and prior to the redesignation of a local exchange company as the universal service provider as provided for herein, for the purposes of the appropriate State agency's periodic certification to the Federal Communications Commission in matters regarding eligible telecommunications carrier status, a local company's status shall not be deemed to affect its eligibility to be an eligible telecommunications carrier, and the appropriate State agency shall so certify.

Further, G.S. 62-110(f6)(1) defines appropriate State agency as:

> the Commission for purposes of any subdivision or other area within the franchise area of a local exchange company, and the Rural Electrification Authority for the purposes of any subdivision or other area within the franchise area or territory of a telephone membership corporation.

These provisions address the very limited situation where, for instance, the developer of a residential subdivision contracts with a CLP, Voice over Internet Protocol (VoIP), or Commercial Mobile Radio Service (CMRS) provider to be the exclusive telecommunications provider within the subdivision, relieving the incumbent LEC (ILEC) or TMC of carrier-of-last-resort responsibility; the CLP, VoIP or CMRS provider ceases to serve; and the carrier-of-last-resort responsibility is reassigned to the incumbent. Before reassignment, in this limited situation, the NCREA certifies ETC status to the FCC with respect to universal service in TMC service areas.

These provisions are based on the assumption that the carrier-of-last-resort responsibility in TMC service areas is in the process of being reassigned to the TMC and designates the NCREA to make periodic certification to the FCC for purposes of high-cost subsidies in rural areas. These provisions do not address the situation at issue in this case – CLP ETC designation for Lifeline-only service in TMC study areas addressed by the Telecommunications Act of 1996 and the FCC's forbearance order. Indeed, if the NCREA has the extensive jurisdiction over carriers in the TMC study areas advocated by Intervenors, this limited grant of authority in this discrete situation would be unnecessary. The fact that the legislature created a carve-out from this Commission's authority for some specific circumstances, but chose not to create a similar carve-out for the specific circumstances debated in this matter, further evidences this Commission's authority. Under the doctrine of statutory construction, expressio unius est exclusio alterius (expressed mention and implied exclusion),[1] the provisions at issue are evidence of a legislative intent disfavoring NCREA jurisdiction over CLPs in the situation at issue here.

Intervenors argue that if this Commission possesses jurisdiction over CLPs in a TMC study area, by extension the NCREA should have jurisdiction over TMCs outside the TMC study area. This argument is irrelevant for several reasons. North Carolina General Statutes Section 117-30(a) prevents a TMC from serving in these areas in most instances. In instances where this statute does not control, this Commission in fact would not have jurisdiction over TMCs outside of their study area boundaries because they are not public utilities. This Commission in nearly every case does not regulate member-owned service providers, be they telecommunications providers or other utility-like service providers. In recognition of these facts, TMCs wishing to compete outside their study area boundaries to serve non-members have established CLP subsidiaries which have received CPCNs issued by and under the regulation of this Commission.

Intervenors cite other instances where the Commission has determined that the NCREA or the FCC is the proper agency to make decisions as support for their argument that it should do so here. Even if it had been appropriate for the NCREA to act in the cases cited, the facts here are distinguishable. Cases involving wireless carriers are inapposite because, by statute, this Commission has no jurisdiction over these carriers. The wireless cases cited involved a request for the Commission to concur with the FCC's proposal to redefine the requested wire centers in the study areas of ILECs and TMCs. See In the Matter of Designation of Carriers Eligible for Universal Service Support—Petition of US Cellular for Commission Concurrence in Redefining Certain Rural Service Areas, Order Seeking Comments and Dismissing Petition as to TMCs, N.C.U.C. Docket No. P-100, Sub 133E, (August 14, 2008). However, the fact that the wireless carriers in these cases received ETC designation from the FCC, rather than the NCREA, for service in TMC service areas, further supports the NCREA's lack of jurisdiction in this matter. While the classification of an entity as a CLP or as a wireless carrier is central to this Commission's authority to regulate the entity by statute, were one to accept Intervenors' rationale of ancillary or supplemental jurisdiction and subsequent authority in TMC service areas, it would not be relevant whether the provider was a CLP or a wireless carrier as a distinction for determining the NCREA authority. Under Intervenors rationale, merely the fact that the wireless carrier was serving in a TMC area should suffice for NCREA jurisdiction over ETC designation. Thus, the FCC's ETC

[1] North Carolina courts have addressed this doctrine on several occasions. See Evans v. Diaz, 333 N.C. 774, 779-780, 430 S.E.2d 244, 247 (1993) ("Under the doctrine of expressio unius est exclusio alterius, when a statute lists the situations to which it applies, it implies the exclusion of situations not contained in the list"). See also Johnson v. Forsyth County, 743 S.E.2d 227, 229 (2013) ("A statute that provides a clear enumeration of its inclusion is read to exclude what the General Assembly did not enumerate"); Univ. of N.C. v. Feinstein, 161 N.C.App. 700, 704, 590 S.E.2d 401, 403 (2003); Dunn v. N.C. Dep't of Human Res., 124 N.C.App. 158, 161, 476 S.E.2d 383, 385 (1996); Morrison v. Sears, Roebuck & Co., 319 N.C. 298, 303, 354 S.E.2d 495, 498 (1987).

designation of wireless carriers in TMC areas reinforces the lack of NCREA jurisdiction over a public utility requesting the same designation. In the matter at hand, however, unlike a wireless carrier which must seek ETC designation from the FCC, this Commission has been statutorily provided jurisdiction over public utilities such as TWCIS (NC).

Significantly, the examples cited by Intervenors did not result in two state agencies making regulatory determinations for any single service provider. Yet, this is the result Intervenors request here. No authority supports this result, and it is poor and costly public policy.

Further, requests by competing carriers for interconnection agreements or arbitration over interconnection agreement disputes are not controlling either. Even if the NCREA has jurisdiction to address requests for terms on interconnection to TMCs, here TWCIS (NC) is not requesting any relief whatsoever from a TMC. TMCs and their representatives are participants in this case as intervenors, not as respondents. Just as this Commission cannot entertain requests by public utilities for relief against third parties, such as collections by utilities of past due bills from their customers, the NCREA has no jurisdiction here over a public utility seeking ETC designation from "the" State commission where no relief is sought from a TMC.

One analogy of note that supports the Commission's decision in this matter is through reference to the Electric Act of 1965. The Commission is authorized to divide the State into exclusive electric service areas and to assign the areas among the electric public utilities and the electric membership corporations (EMCs). G.S. 62-110.2(c)(1). However, there are exceptions to the exclusivity within the designated boundaries. For example, one electric supplier already serving within the service area of another when the assignments are made can serve new customers thereafter located in proximity to its pre-existing lines. G.S. 62-110.2(b)(5), (6) and (7). When this occurs, the regulatory authority over the provider is determined by the nature of the service, not by the location of the new customer. This Commission does not relinquish jurisdiction over Duke Energy Carolinas, LLC, for example, when it establishes service to a new electric customer in an EMC's otherwise exclusive service area.

While arguing on the one hand that the NCREA has exclusive jurisdiction to make the ETC determination for TWCIS (NC) in TMC study areas, Intervenors also suggest that the Commission abstain in preference to NCREA's better suited qualifications to address TWCIS (NC)'s request. The Commission cannot abstain in deference to the NCREA if, as Intervenors contend, it has no jurisdiction to waive. Nevertheless, the Commission does not accept the argument that the NCREA is the best agency to make the decision here. North Carolina Utility Commissioners must be non-partial. They cannot be employees of or hold an ownership interest in the public utilities they regulate. G.S. 62-11. However, the NCREA board is composed of members of EMCs and TMCs. Neutrality is conspicuously missing. Moreover, the NCREA's processes, procedures and staffing are not appropriately suited to serve as a "State commission" to make the types of determination at issue here. TWCIS (NC) cites an example of an arbitration it has sought for which it has awaited a NCREA ruling for eight years.[1] NCREA must bring in outside arbitrators. Its staff, though

[1] This unfortunate situation has required TWCIS (NC) to petition the FCC for relief. The FCC in fact provided this relief by order issued on November 1, 2013. See TWCIS (NC)'s Statement of Supplemental Authority, filed in Docket No. P-100, Sub 133C, on November 5, 2013.

competent, is limited in size, and addressing issues such as those under consideration here are outside its customary responsibilities.

Intervenors attempt to complicate what boils down to a simple question – what is the "State commission" which under the laws of this State has regulatory jurisdiction with respect to intrastate operations of carriers. TWCIS (NC) indisputably meets the definition of a public utility in G.S. 62-3(23)(a)(6). North Carolina General Statutes Section 62-30 states that this Commission:

> shall have and exercise such general power and authority to supervise and control the public utilities of the State as may be necessary to carry out the laws providing for their regulation, and all such other powers as may be necessary or incident to the proper discharge of its duties.

There is no provision in Chapter 117 or elsewhere in the General Statutes that gives regulatory authority to the NCREA over a public utility. TWCIS (NC) cites two authorizing statutes; Intervenors cite none. Intervenors have stated that the NCREA has authority over TWCIS (NC) in this matter based on ancillary jurisdiction, or some type of supplemental jurisdiction that flows through its power to regulate TMCs; however, just as this Commission has no authority, express or otherwise, except that given to it by statute, neither does the NCREA. Edmisten, 291 N.C. 451. To find that the NCREA has regulatory jurisdiction over TWCIS (NC) with respect to intrastate operations in a matter that does not directly involve a TMC would be exactly that – a grant of authority that is not given to it by statute. Conversely, this Commission has been granted regulatory authority over public utilities and has not been limited in that authority in these specific circumstances.

CONCLUSION

After carefully considering the comments, reply comments, the arguments of the parties and the record proper, the Commission concludes that this Commission is the appropriate "State commission" to address TWCIS (NC)'s Petition for Designation as a Lifeline-only ETC in franchise areas or territories currently being served by TMCs.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of January, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioners Susan W. Rabon and James G. Patterson, concurring.
Commissioners Bryan E. Beatty and ToNola D. Brown-Bland, dissenting.

DOCKET NO. P-100, SUB 133C

COMMISSIONER JAMES G. PATTERSON, CONCURRING: In this case, the telephone membership corporations (TMCs) and the North Carolina Rural Electrification Authority (NCREA) argue that the NCREA, and not the Commission, is the "State commission" pursuant to federal law with jurisdiction over Time Warner Cable Information Services (North Carolina), LLC (TWCIS (NC)), and its request for designation as an eligible telecommunications carrier (ETC) in TMC study areas. I cannot agree and, therefore, concur in the decision reached by the majority.

The NCREA, in its comments, "asserts that the NCREA, not the Utilities Commission, is the appropriate agency to determine TWCIS NC's request for ETC designation," arguing that the NCREA "is the state agency with jurisdiction over intrastate operations of carriers in rural study areas and has direct jurisdiction over [TMCs]." The TMCs similarly assert that the NCREA is the proper agency to make these designations and the Commission should deny TWCIS (NC)'s request or refer the matter to the NCREA. I agree that the NCREA is the State agency with jurisdiction over TMCs in TMC study areas, but cannot agree that authority gives the NCREA jurisdiction over other carriers, including TWCIS (NC), in TMC study areas.

The NCREA like the Commission, is a "creature of the legislature" and has no authority except that given to it by statute.[1] The NCREA is funded by a regulatory fee imposed upon "every electric and telephone membership corporation subject to the jurisdiction of the Authority." G.S. 117-3.1(a). The monies received are deposited into a special fund in the office of the State Treasurer, and "[a]ll funds credited to the NCREA Fund shall be used <u>only</u> to pay the expenses of the Authority in regulating electric and telephone membership corporations in the interest of the public as provided by this Chapter." G.S. 117-3.1(d) (emphasis added). Thus, while the NCREA has jurisdiction over TMCs in TMC study areas, it is prohibited by its own statute from regulating carriers other than TMCs. I, therefore, cannot agree with the TMCs and the NCREA that the NCREA is the "State commission" with jurisdiction in this case over TWCIS NC's request for ETC designation in TMC study areas.

/s/ James G. Patterson
Commissioner James G. Patterson

DOCKET NO. P-100, SUB 133C

COMMISSIONERS TONOLA D. BROWN-BLAND AND BRYAN E. BEATTY, DISSENTING: On July 23, 2013, TWCIS (NC) filed a petition requesting that the Commission designate it as an ETC in portions of its service territories that overlap with ILEC regulated by this Commission and portions of its (non-Commission assigned) territories which overlap with TMCs that are not regulated by this Commission. Further, in its petition, TWCIS (NC) requested that the Commission confirm "the Commission's authority to designate ETC status in TMC areas." Petition p. 6. By its decision here today, the majority has acquiesced to TWCIS (NC)'s request. It found that "this Commission is the <u>appropriate</u> "State Commission" to address TWCIS (NC)'s

[1] <u>See, e.g.,</u> <u>State ex rel. Utilities Comm'n v. Edmisten</u>, 291 N.C. 451, 232 S.E.2d 184 (1977).

Petition for Designation as a Lifeline-only ETC in franchise areas or territories currently being served by TMCs." Emphasis added. Majority Opinion, p 17. We respectfully disagree and dissent.

At the outset, we note that the Majority's opinion as well as much of its supporting analysis focuses on the whether the Commission or the NCREA is the appropriate state Commission to make this determination. This focus is misplaced. The issue raised by TWCIS (NC) is not whether the Commission or the NCREA is the proper or appropriate state commission to resolve a request for ETC designation in TMC service areas. In our opinion, the only real issue in this case is whether the Commission has jurisdiction, *i.e.*, has the General Assembly authorized the Commission to designate a Commission certificated and regulated CLP as an ETC in areas served by TMCs. When the focus is placed on this issue as opposed to whether this Commission or the NCREA is the better Commission to make this designation, we conclude that the Commission does not have jurisdiction to make the requested designation for the following reasons.

The federal Telecommunications Act in pertinent part provides that:

> (2) Designation of eligible telecommunications carriers. A State commission shall upon its own motion or upon request designate a common carrier that meets the requirements of paragraph (1) as an eligible telecommunications carrier for a service area designated by the State commission. Upon request and consistent with the public interest, convenience, and necessity, the State commission may, in the case of an area served by a rural telephone company, and shall, in the case of all other areas, designate more than one common carrier as an eligible telecommunications carrier for a service area designated by the State commission, so long as each additional requesting carrier meets the requirements of paragraph (1). Before designating an additional eligible telecommunications carrier for an area served by a rural telephone company, the State commission shall find that the designation is in the public interest.

47 U.S.C. 214(e)(2).

Additionally, in 47 U.S.C. 153(48), the Act defines state commission thusly:

> (48) State commission. The term "State commission" means the commission, board, or official (by whatever name designated) which <u>under the laws of any State has regulatory jurisdiction with respect to intrastate operations of carriers</u>. Emphasis added.

The FCC adopted similar language in its implementing regulations to define a state commission. The regulation states:

> State commission. The term "state commission" means the commission, board or official (by whatever name designated) that, <u>under the laws of any state, has regulatory jurisdiction with respect to intrastate operations of carriers</u>. Emphasis Added.

47 C.F.R. 54.5.

Pursuant to the aforementioned sections, TWCIS (NC) filed a Petition requesting that the Commission designate it as an ETC for those portions of the State of North Carolina that TWCIS (NC) itself has decided to serve[1] that overlap with the service territories of NCREA regulated TMCs. Thus, the only pertinent issue presently before the Commission in this proceeding is whether this Commission has jurisdiction "under the laws of [this] state" to designate TWCIS (NC) as an ETC in those portions of TWCIS(NC)'s self-determined service territories that overlap with the service territories of TMCs. 47 U.S.C. 153(48).

Our analysis of state law leads us to conclude that the General Assembly did not authorize this Commission to grant ETC status to CLPs such as TWCIS (NC) in TMC service areas. We reach this conclusion because our appellate courts have consistently held that as an administrative agency created by statute, the Commission has no regulatory authority except such authority as is conferred upon it by the General Assembly. Utilities Commission v. Mountain Electric Cooperative, Inc., 108 N.C. App. 283, 423 S.E. 2d 516 (1992) aff'd 334 N.C. 681, 435 S.E. 2d 71 (1992). After examining the authorizing legislation of the Public Utilities Act, we find no indication that the General Assembly conferred such authority upon the Commission. To the contrary, we conclude that the General Assembly specifically limited the Commission's jurisdiction to authorize and thereby regulate CLP services within a TMC study area.

In Chapter 62 of the General Statutes, the General Assembly established the Utilities Commission and granted the Commission broad regulatory authority over public utilities in this State. See G.S. 62-2 and G.S. 62-30. A public utility is defined in G.S. 62-3(23)a. 6 as a person owning or operating equipment or facilities for: "conveying or transmitting messages or communications by telephone or telegraph, or any other means of transmission, where such service is offered to the public for compensation." By its terms, this statute permits any person or entity that conveys messages by telephone, telegraph or any other means of transmission to the public for compensation to be considered a "public utility." In its pleadings and argument before the Commission, TWCIS (NC) seized upon this statute to support its contention that the legislature granted this Commission ETC designation authority in TMC areas because TWCIS (NC) is clearly encompassed within the definition of public utility. TWCIS (NC) Reply Comments, p. 6. While we agree with the contention that TWCIS (NC) is a public utility, we fundamentally disagree with TWCIS (NC)'s implicit contention that this fact alone is dispositive of the Commission's jurisdiction to determine the issues raised by this Petition.

The Commission's regulatory jurisdiction over a public utility cannot be determined solely by whether the entity providing such service falls within the definition of public utility. In many instances, reliance on this one factor would give an incorrect impression of the breadth and the scope of the Commission's jurisdiction to regulate entities that are providing public utility type services because it ignores other more relevant actions by the General Assembly meant to explain and qualify the Commission's jurisdiction. In our view, the Commission's jurisdiction is best understood by reviewing other more specifically crafted provisions of the Public Utilities Act that

[1] TWCIS (NC) has not sought Commission permission to serve in TMC territories. Thus, TWCIS (NC)'s "service territories" in TMC areas have been self-determined.

shed light on the General Assembly's intent in this regard in conjunction with the definition set forth in G.S. 62-3(23). Emphasis added.

A review of the Public Utilities Act reveals that the General Assembly has on many occasions indicated that it did not intend the definition of public utility contained in G.S. 62-3(23) to be the sole determinant of the Commission's jurisdiction. That is, the General Assembly has acted numerous times to remove entities falling clearly within the classic definition of a public utility as defined in G.S. 62-3(23)a. 6 from the regulatory oversight of the Commission. An obvious example is wireless telecommunications service. At one time, wireless telecommunications service "clearly [fell] within the definition of public utility in G.S. 62-3." Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257, 268, 148 S.E.2d 100 (1966). As such, it was regulated by the Commission until 1995. In that year, the General Assembly saw fit to remove the Commission's regulatory authority over such public utility operations by exempting telecommunications service that was delivered by commercial mobile radio service provider from the definition of a public utility. See G.S. 62-3(23)j which became effective on January 1, 1996.

The General Assembly did likewise with telecommunications service provided by TMCs, municipalities, and the University of North Carolina. Each of the aforementioned provides telecommunications services for compensation to the public within the meaning of G.S. 62-3(23)a. 6. Based upon the "public utility" definition, the Commission should have regulatory jurisdiction over these entities and the services that they provide. Yet each is not and cannot be regulated by the Commission because they have been excluded from the definition of a "public utility" by the actions of the General Assembly. Moreover, the services that they provide are excluded from regulation by the Commission. In our opinion, the General Assembly acted in a similar, though much narrower, manner with respect to CLP telecommunications public utilities. In the Public Utilities Act, the General Assembly clearly indicated that the Commission is not authorized to permit CLPs to provide telecommunications service in TMC areas and therefore the Commission should not have the authority to regulate CLPs in those areas.

Our opinion in this regard, is guided by the language of the relevant statutes, certain principles of statutory construction, and North Carolina case law. Looking first to the applicable statutes, it is the law of the State that the Commission has statutory authority "to regulate public utilities generally . . . and in the manner . . . set forth in this Chapter [62]. G.S. 62-2(b). The manner in which public utilities are regulated under Chapter 62 begins with establishment of a franchise or a "grant of authority by the Commission to any person to engage in business as a public utility," as provided in Article 6 of Chapter 62, captioned, "The Utility Franchise." G.S. 62-3(11). Pursuant to G.S. 62-110(a) of Article 6, a franchise or grant of authority is created or established on the issuance by the Commission of a certificate. "No public utility shall . . . begin . . . operation of any public utility plant or system . . . without first obtaining from the Commission a certificate" of public convenience and necessity. G.S. 62-110(a).

> "Each franchise shall specify the service to be rendered . . . and the territory within which, a motor carrier or other public utility is authorized to operate: and there shall at the time of issuance . . . be attached to the privilege granted by the franchise such reasonable terms, conditions and limitations as the public convenience and necessity may from time to time require . . . and such terms and conditions as are necessary to

> carry out, with respect to the operations of . . . [a] public utility, the requirements established by the Commission under this Chapter [62] . . . .

G.S. 62-113(a). Thus, unless exempted from Chapter 62 or excluded from the definition of a public utility, no person in North Carolina shall operate a public utility system without a grant of authority from the Commission, which specifies its service territory of operation and the terms and conditions that are required by the public convenience and necessity and that are necessary to carry out the requirements established by the Commission under the provisions of Chapter 62.

TWCIS (NC) is the holder of a certificate of public convenience and necessity having applied for and been granted a certificate by the Commission authorizing it to provide local exchange and exchange access service in accordance with the provisions of G.S. 62-110. Therefore, on its face, contrary to assertions made by TWCIS (NC) and accepted by the Majority, TWCIS (NC)'s franchise or grant of authority, limits its service territory as a competing local provider to areas outside of areas served by TMCs.

TWCIS (NC)'s certificate contains an express term, condition and limitation that provides it with authorization to provide local exchange services in accordance with or subject to the whole of G.S. 62-110, without exception or excuse from any part thereof. G.S. 62-110(f1) specifically addresses the Commission's authority or jurisdiction to issue certificates of franchise to competing local providers (CLPs). This statutory provision gives the Commission express authority to issue a certificate permitting a CLP, meeting the definition of G.S.62-3(23)a.6 and making certain other showings, to provide local exchange or exchange access services, "without regard to whether local telephone service is already being provided in the territory for which the certificate is sought." However, the legislature's seemingly broad grant of Commission authority or jurisdiction, authorizing the Commission to grant to CLPs the authority to provide local exchange service, is immediately circumscribed by subsections 110(f2) and 110(f3), both of which contain express language stating that the provisions of subsection (f1) "shall not be applicable to [certain] areas." Subsection (f3) expressly states that "the provisions of subsection (f1) of this section shall not be applicable to areas served by telephone membership corporations." As part of G.S. 62-110, this limitation of the Commission's jurisdiction applies to and is "attached" to TWCIS (NC)'s certificate. Accordingly, TWCIS (NC) is not authorized to provide local service in any area served by a TMC because the Commission is totally lacking in authority or jurisdiction to authorize any CLP to serve in such territory.

To further expound and most salient to the jurisdiction question now confronting the Commission, TWCIS (NC) is not prohibited from providing local service in areas served by TMCs merely because its Commission-issued certificate states as much by its reference to 62-110, but because *the Commission absolutely lacks jurisdiction, as provided in (f3,) to issue a certificate authorizing local service in an area served by a TMC.* Subsection (f3) serves no purpose other than to take from the Commission regulatory authority over competing local exchange service providers with respect to areas served by TMCs. Subsection (f1) states "the Commission is authorized . . . to issue a certificate," and subsection (f3) states "the provisions of subsection (f1) of this section shall not be applicable to areas served by [TMCs]." The reasonable conclusion to draw from (f3) is that the Commission is not authorized to issue a certificate, the prerequisite to regulation of a public utility under Chapter 62, to a CLP, *e.g.* TWCIS (NC), in areas served by TMCs. In legal parlance, this lack of authority is understood to mean the same thing as a lack of jurisdiction and no provision of federal law can overrule a state law expressly denying jurisdiction, except perhaps, as will be discussed below, if the federal law preempts the entire field that is the subject of the federal law.

Next we address the principles of statutory construction and case law in support of our interpretation of the statutes discussed above. The first and foremost rule of statutory construction is that "[l]egislative intent controls the meaning of a statute." Shelton v. Morehead Memorial Hospital, 318 N.C. 76, 81, 347 S.E.2d 824, 828 (1986). This rule underlies all others which aid a court in construing a statute. Second, to determine legislative intent, the Commission must analyze the statute as a whole, considering the chosen words themselves, the spirit of the act, and the objectives the statute seeks to accomplish. Third, the plain meaning of the words chosen by the legislature; if they are clear and unambiguous within the context of the statute, are to be given their plain and ordinary meanings. Hyler v. GTE Products Co., 333 N.C. 258, 262, 425 S.E.2d 698, 701 (1993). Fourth, the legislative intent is to be ascertained by examining the title of the statute, the legislative history and the law as it prevailed before the statute in question was enacted to determine the mischief that the enactment was intended to remedy. Lenox, Inc. v. Tolson, 353 N. C. 659, 664, 548 S.E. 2d 513, 517 (2001). Fifth, the rules of statutory construction require that a more specific statute controls over a statute of general applicability. That is, when two statutes overlap, the special and particular statute shall control unless it can be clearly shown that the legislature intended otherwise. Sixth, it is always presumed that the legislature acted with care and deliberation and that each word of a statute is to have meaning, where reasonable and consistent with the entire statute. Finally, in determining legislative intent, the statutes dealing with the same subject matter must be construed in para materia, and harmonized, if possible to give effect to each. With those principles in mind, we examine the legislative history of pertinent provisions of Chapter 62 and the law as it prevailed before the enactment of provisions pertaining to regulatory authority permitting CLPs to provide local exchange services to determine if the Legislature intended to authorize the Commission to designate an ETC in TMC service areas. We conclude that it does not.

Prior to 1995, the only Commission recognized, regulated and authorized public utilities that provided local exchange and exchange access service to consumers for compensation were incumbent local exchange companies (ILECs). Other companies desiring to provide competitive telephone service in the territories served by local exchange companies (LECs) generally were not allowed to do so because North Carolina public policy favored monopoly service over competitive alternatives. Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257, 271, 148 S.E.2d 100 (1966). That changed in 1995 when the General Assembly enacted S.L. 1995-27: An Act to Provide the Public with Access to Low Cost Telecommunications Service in a Changing Competitive Environment (House Bill 161).[1] The purpose of House Bill 161 was to extend competition to the Commission-regulated local telephone market. To do that, the General Assembly created a unique class of territorially limited telecommunications public utility called a Competing Local Provider (CLP) by amending G.S. 62-3 to add a new subdivision which read:

[1] House Bill 161 preceded the adoption of the Telecommunications Act of 1996. The purpose of the Telecommunications Act of 1996 was also to create competition within the local telephone market.

> (7a) Competing local provider means any person applying for a certificate to provide local exchange and exchange access services in competition with the local exchange company. Emphasis added.

Also, as part of the 1995 Act, the General Assembly amended G.S. 62-3 to add a new subdivision which read:

> (16a) Local exchange company means a person holding, on January 1, 1995, a certificate to provide local exchange services or exchange access services.[1]

And, finally, in Section 4 of the Act, the General Assembly amended G. S. 62-110 to add three new sections, the above-discussed (f1), (f2) and (f3).[2] In pertinent part the sections read:

> (f1) Except as provided in subsection (f2) of this section, the Commission is authorized, following notice and an opportunity for interested persons to be heard, to issue a certificate to any person applying to provide local exchange or exchange access services as a public utility as defined in G.S. 62-3(23)a.6, without regard to whether local telephone service is already being provided in the territory for which the certificate is sought,….
>
> (f2) The provisions of subsection (f1) of this section shall not be applicable to franchised areas within the State that are being served by local exchange companies with 200,000 access lines or less located within the State...
>
> (f3) The provisions of subsection (f1) of this section shall not be applicable to areas served by telephone membership corporations formed and existing under Article 4 of Chapter 117 of the General Statutes and exempt from regulation as public utilities, pursuant to G.S. 62-3(23)d. and G.S. 117-35….

Although this language was adopted before the Telecommunications Act of 1996 was enacted by the federal government, to date, none of the pertinent language cited above has been changed by the General Assembly. It appears therefore not to accommodate many of the changes mandated by the Telecommunications Act. The Majority seizes upon this inaction to suggest that federal law therefore supplements and augments the Commission's authority to designate a CLP as an ETC in areas served by TMCs. Through this supplemented authority, the Majority argues that the Commission is authorized to make this designation in spite of the express prohibition by the General Assembly to the contrary. The Majority cites to no authority in federal or state law that stands for this proposition. Until such citation is provided, we believe that the words of the

[1] TMCs were in existence but did not provide service pursuant to a certificate when the statute permitting CLPs to compete was enacted.

[2] The General Assembly also enacted G.S. 62-110(f2). For the issues raised by TWCIS (NC) in its Petition, G.S. 62-110(f2) is inapposite.

General Assembly stand as written and their interpretation must be determined by the rules of statutory construction.[1]

When interpreted in light of the history stated above, G.S. 62-110(f1) through (f3) indicate that the Legislature had two goals when these provisions were enacted: (1) it intended to provide consumers that were receiving local telephone service from local exchange companies[2] with competitive alternatives in the form of CLPs; and, (2) it did not intend to allow the Commission to extend these competitive CLP alternatives to consumers being served by monopoly local telephone companies created under Chapter 117, i.e. TMCs.[3] No other conclusion can be drawn from the words in G.S. 62-110 (f1) and (f3) when they are given their plain and ordinary meanings and considered in pari materia.

To accomplish the first goal, the General Assembly adopted (f1) which authorized the Commission "following notice and an opportunity for interested persons to be heard, to issue a certificate to any person applying to provide local exchange or exchange access services as a public utility as defined in G.S. 62-3(23)a.6, without regard to whether local telephone service is already being provided in the territory for which the certificate is sought." Emphasis added. To accomplish the second goal, the General Assembly adopted (f3) which forbade the Commission from issuing a CLP certificate to serve "areas served by telephone membership corporations" [4] formed and existing under Article 4 of Chapter 117 of the General Statutes and exempt from regulation as public utilities, pursuant to G.S. 62-3(23)d. and G.S. 117-35.

By using this phrase, i.e., "areas served by telephone membership corporations" the legislature clearly intended to constrain the scope of the Commission's perceived jurisdiction over territories served by TMCs. When contrasted with the seemingly unlimited jurisdiction[5] that the General Assembly gave to the Commission in (f1) to allow CLP service in any other area in the state "without regard to whether local telephone service is already being provided in the territory

[1] Moreover, the General Assembly since amended Article 6 of Chapter 62 in 2005 with full knowledge of the existing state and federal law, but did not, in its judgment and prerogative, see fit to change the cited provisions. See S.L 2005-385 which enacted G.S. 62-110(f4), (f5) and (f6).

[2] As the TMCs noted in their comments and arguments, these provisions and the term "local exchange company" clearly were not intended to apply to TMCs because the only carriers holding certificates on January 1, 1995 were incumbent local exchange companies.

[3] The General Assembly also intended to restrict CLP service in LEC franchise areas that had less than 200,000 access lines until certain circumstances were met. G.S. 62-110(f2).

[4] Had the General Assembly not adopted the language forbidding the Commission from issuing a certificate for the "areas served by telephone membership corporations formed and existing under Article 4 of Chapter 117 of the General Statutes", and instead simply exempted TMCs from Commission oversight because they were not public utilities, then, under the law as it existed at the time, CLPs could have freely entered into the TMCs territories and the Commission would not have been obligated to protect the TMCs from such intrusion. See Southern Bell v. Pineville,13 N.C. App. 663 (1972) and 17 N.C. App. 522 (1973) which interpreted G.S. 62-110(a) to allow a Commission-regulated telecommunications carrier to provide public utility service to an area that was receiving or could receive service from an entity that was statutorily exempt from Commission regulation. Further, those decisions held that the exempt entity was not entitled to Commission protection of its territorial monopoly.

[5] The Commission's jurisdiction was limited as noted above in Footnote 7.

for which the certificate is sought", no other interpretation could be possible. (While there could have been many reasons why the General Assembly chose to the limit the Commission's jurisdiction to authorize and thereby regulate CLP service in TMC areas, the one that comes immediately to mind, and one that was suggested by the TMCs in their argument, is that the General Assembly believed that the NCREA was more acutely attuned to the needs and wants of the consumers in those areas and would therefore have been able to determine if such service was needed in those service areas.)

From the plain words of the statute, it is obvious that the constraint intended was different than, and in addition to, existing jurisdictional constraints that the General Assembly used when exempting a particular entity from the definition of a public utility in G.S. 62-3(23). For instance, it was far different from the prior legislative practice of totally exempting a provider such as a wireless carrier, a municipality or a TMC from Commission jurisdiction. See G.G. 62-3(23) j.

Here, the General Assembly took a more nuanced approach. It prevented the Commission from allowing its regulated CLPs to provide service in areas of the state served by TMCs. It thus preserved Commission regulation of its certificated CLPs in the rest of the state while precluding any Commission regulation in TMC areas by forbidding the Commission from authorizing service in those specified areas. This approach was fundamentally different from the General Assembly's prior practice of completely exempting an entity or a class of entities from Commission regulation. To highlight this difference, in (f3), the General Assembly first established the new territory limitation on CLPs and the Commission's authority. It thereafter contrasted this new limitation by referring back to the existing complete and total exemption that it had created for TMCs. This underscored that the new territorial limitation of the Commission's authority was unique. Any other explanation for the words chosen by the General Assembly and the juxtaposition of those words would render the reference to the classic TMC exemption useless and meaningless.

In our view, this is a reasonable construction of the statute. Construing the statute in this manner allows "each word of a statute to have meaning, where reasonable and consistent with the entire statute, because "[i]t is always presumed that the legislature acted with care and deliberation...." State v. Benton, 276 N.C. 641, 658, 174 S.E.2d 793, 804 (1970). Any other construction would render those newly adopted words in the 1995 amendment superfluous. The canons of statutory construction prohibit such a construction. State v. Cloninger, 83 N.C.App. 529, 531, 350 S.E.2d 895, 897 (1986).

In its argument, TWCIS (NC) sought to diminish the importance of this statute in resolving the issue in this case by contending that the territorial restriction contained in subsection (f3) is not "germane" to the question before the Commission because TWCIS (NC) is not requesting Commission certification to provide service in the TMC territories. Rather, TWCIS (NC) argues, it is merely seeking a Commission determination of regulatory status according to federal law for services that it is providing or will provide in North Carolina pursuant to authorization "from other sources." Reply Comments, pp. 9-10. According to TWCIS (NC), subsection (f)(3) is not germane to the issues in this case because it only prohibits the Commission from issuing a CPCN allowing TWCIS (NC) to provide service in TMC areas and TWCIS (NC) is not asking for a CPCN to serve those areas. According to TWCIS (NC), the broad regulatory authority granted to the Commission in G.S. 62-30 to issue a declaration of ETC status to TWCIS (NC) is unaffected by the specific limitation imposed by the General Assembly in Subsection (f)(3) on the Commission's right to authorize public utility service in areas served by TMCs. We disagree for the following reasons.

First, TWCIS (NC) petitioned this Commission as a G.S. 62-3(7a) certificated CLP to designate it as an ETC in areas served by TMCs. It did not invoke the Commission's jurisdiction as a G.S. 62-3(23)a.6 LEC telecommunication public utility seeking a Commission designation of ETC status. Nor did it invoke the Commission's jurisdiction as a federally authorized and regulated provider of telecommunications services in TMC areas. Pursuant to G.S. 62-110(f) and by the clear terms of its CPCN, TWCIS (NC), the CLP, is authorized to provide service in ILEC territories.[1] It is not authorized to provide service in TMC territories as a LEC. To the extent that it may be doing so pursuant to its CPCN as a Commission certificated CLP, its activities would be beyond the scope of its CPCN, ultra vires and unlawful.

Because TWCIS (NC) filed its petition as a certificated CLP, the precise question raised by the petition is not whether the Commission has jurisdiction to designate a public utility that provides telecommunications services as an ETC in those service areas served by TMCs. Instead, the question is whether the Commission has jurisdiction to designate a certificated CLP as an ETC in areas served by TMCs. TWCIS (NC) agrees with this assessment. See p. 2 of its Reply Comments where it states: "the Public Staff accurately captures the lone issue presently before the Commission: whether the Commission… is the agency with jurisdiction to designate a competing local provider of telecommunications services ("CLP) as an ETC with a service area that includes portions of telephone membership corporation ("TMC") service areas."

This is a critical distinction. The Commission's regulatory authority over other telecommunications service providers and the Commission's regulatory authority over certificated CLPs, while overlapping in certain areas, are most certainly separate and distinct in this regard. G.S. 62-110(f)(3), G.S. 62-30 and G.S. 62-3(23) a.6 deal with the Commission's authority to regulate public utilities. Sections G.S. 62-30 and G.S. 62-3(23)a.6 articulate broad and general regulatory principles applicable to all telecommunications public utilities. Under these sections and the applicable law, the Commission has broad regulatory authority to allow ILECs to provide service in these areas. Southern Bell v. Pineville,13 N.C. App. 663 (1972) and 17 N.C. App. 522 (1973). With such authority, the Commission perhaps has the ability to authorize service and therefore make an ETC designation for those carriers in areas served by TMCs. See Agreement of Administrative Procedures for Telephone Service as Adopted by the North Carolina Utilities Commission and the North Carolina Rural Electrification Authority executed on December 31, 1957. The Commission does not have such jurisdiction pursuant to these statutes (or some other general provision in the Public Utilities Act) to designate a CLP such as TWCIS (NC) as an ETC in TMC service areas because the Commission's jurisdiction with regard to CLPs is specifically addressed in subsections (f1) and (f3) of G.S. 62-110 and G.S. 62-3(7a).

[1] Again, although the Majority's statement that the "CPCN and the Commission's order make no specific exceptions in reference to G.S. 62-110(f)(3) or otherwise with respect to TMC study areas" may have a certain literal appeal, it is incorrect as a legal matter. See Majority Opinion p. 10. Although the CPCN does not specifically reference G.S. 62-110(f)(3), it does reference G.S. 62-110 in general which includes the aforementioned section. Therefore, it is not correct to say that TWCIS (NC) was or is permitted by its CPCN to serve in the TMC areas. The CPCN cannot authorize service in those areas since such service is precluded by the terms of the statute which statute is expressly incorporated in the TWCIS (NC) CPCN by reference and by operation of law.

These sections and G.S. 62-2(b)[1] severely circumscribe the Commission's broad regulatory authority over CLP service in TMC areas. Our appellate courts have held that "[t]he applicable rule of statutory construction here is that where one statute deals with a particular subject or situation in specific detail, while another statute deals with the subject in broad, general terms, the particular, specific statute will be construed as controlling, absent a clear legislative intent to the contrary." Nucor Corp. v. General Bearing Corp., 333 N.C. 148, 154–55, 423 S.E.2d 747, 751 (1992). Here the specific statute restricts the Commission over a particular type of telecommunications public utility. The general statute grants the Commission broad regulatory authority over all public utilities without distinction. In this proceeding, however, TWCIS (NC) and the Majority have interpreted these broad and general statutes as controlling of the Commission's jurisdiction over a particular public utility and argued that the statute does not support an interpretation in which the jurisdiction is determined by the more specific statute. In doing so, TWCIS (NC)'s and the Majority's statutory interpretation conflicts with the aforementioned canon of construction.

Additionally, TWCIS (NC)'s interpretation conflicts with the doctrine of expressio unius est exclusio alterius, i.e., the expression of one thing is the exclusion of another. Here, the General Assembly clearly constrained the Commission's jurisdiction to regulate CLPs by precluding the issuance of a CPCN in areas served by TMCs. This specific restriction of the Commission's jurisdiction is a restriction on the Commission's jurisdiction to act on any other matter involving CLP activities in areas served by TMCs. Stated more simply, if the Commission cannot certificate a CLP in those areas, it stands to reason that the Commission cannot thereafter designate a CLP to be an ETC provider in those same areas.

Second, the core of TWCIS (NC)'s argument rests upon the proposition that it is not seeking permission to provide service to customers by its request for a regulatory designation of ETC status. In it pleadings, TWCIS (NC) argues that it does not seek Commission permission to provide telecommunications service in TMC areas, but it instead seeks Commission ETC designation so that it might charge a subsidized rate to customers in such TMC areas once it provides such service. TWCIS (NC) is compelled to make this argument because it is aware that it "may not render [a public utility] service [to the public for compensation pursuant to Chapter 62] without obtaining from the Commission a certificate that public convenience and necessity require or will require such operation," Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257, 268, 148 S.E.2d 100 (1966); G.S. 62-110.

Compliance with these pre-service certification processes is a prerequisite before an entity can invoke the Commission's authority to assist it in providing public utility service in North Carolina. That is, an entity has no standing to invoke the Commission's jurisdiction to assist the entity in providing a public utility service until and unless an entity applies for or receives a certification by the Commission to provide such service. TWCIS (NC) has stated unequivocally that it has not and will not apply to this Commission for such certification. Ordinarily, its failure to request such certification would present a jurisdictional bar to its application to provide such service.

[1] G.S. 62-2(b) in pertinent part states that "authority shall be vested in the North Carolina Utilities Commission to allow competitive offerings of local exchange, exchange access, and long distance services by public utilities defined in G.S. 62-3(23)a.6 and certified in accordance with the provisions of G.S. 62-110…" Emphasis added.

Arguing that it only seeks a designation of regulatory status and not permission to provide public utility service in TMC areas does not permit TWCIS (NC) to avoid the State's certification requirement. TWCIS (NC)'s distinction is premised upon a definition of the term "service" which excludes rates as an element of service. This definition is inconsistent with the Public Utilities Act and prior decisions of this Commission. The Public Utilities Act defines service as follows: "Service" means any service furnished by a public utility, including any commodity furnished as part of such service and any ancillary service or facility used in connection with such service." G.S. 62-3(27). Under this definition, service means the actual telephone service <u>and/or</u> the rate that is ancillary to the service. <u>In re Bellsouth</u>, 168 P.U.R.4th 438 (1996)(NCUC). The Commission so stated in <u>In re Bellsouth,</u> when it held that "a rate element is a specific component, the lowest common denominator of a service." See also <u>In re BellSouth</u>, 2003 WL 663275 (2003) (NCUC) (the Commission held that BellSouth's convenience charge proposal was part of a service offering as defined in G.S. 62-3(27)). Thus, in our view, TWCIS (NC) is required to apply for a CPCN to offer subsidized rate service <u>in areas served by TMCs</u> in order to invoke the Commission's assistance and jurisdiction. However, because of the limitations imposed by the General Assembly, the Commission would not have authority to grant a CPCN allowing TWCIS (NC), the CLP, to offer such rates since the Commission's jurisdiction in this regard has been proscribed.

TWCIS (NC) recognizes the futility of pursuing a Commission certification strategy. In its pleadings, it states that permission to provide service in these areas would not come from the Commission; rather, such authorization would come from "other sources." During the oral argument, the general consensus was that TWCIS (NC) is providing or would be providing these services pursuant to some yet to be identified federal authorization[1]. While this indeed may be true, as TWCIS (NC) notes in its Reply Comments, *"[f]ederal law, of course, cannot confer jurisdiction on a state entity that is otherwise lacking under state law."* Emphasis added.

In its pleadings and during the oral argument, TWCIS (NC) failed to identify any state statute that would allow the Commission to make the requested regulatory designation when federal law or some "other source" permits service in TMC areas <u>but</u> state law specifically forbids the Commission from authorizing such service. Without such a state statute, or a declaration that the regulatory laws of North Carolina have been pre-empted by federal law, the Commission may not make a declaration of regulatory status as requested.

Third, by this request, TWCIS (NC) is asking the Commission to do indirectly what it may not do directly, *i.e*., approve its provision of service in TMC areas. As a practical matter, as noted above, there is no fundamental difference between seeking certification to provide service in a statutorily

[1] Knowing the precise origin of this authorization would be helpful to our analysis because certain telecommunications type services provided in North Carolina such as the services provided by Vonage (a voice over internet protocol provider) are authorized by federal law. The Commission, however, has no regulatory authority over those services. That is, the Commission has no subject matter jurisdiction over these services. It is the petitioner's responsibility and burden to prove that the Commission has subject matter jurisdiction over the services being provided and the remedy being requested. Here, our review of the transcript yields no more precision with regard to the source of TWCIS (NC)'s ability to serve in TMC territories than the ubiquitous "federal authorization". Because of this imprecision, the Petitioner has failed to sustain its burden of proving that the Commission has jurisdiction over the subject matter of this issue and thus its request should be denied. Denial would be the appropriate remedy in this case even though no party has challenged the Petitioner's right to serve in TMC areas because subject matter jurisdiction cannot be waived or conferred upon the Commission by the consent of the parties.

prohibited area and asking for a designation that allows one to serve the same proscribed area in a manner that is more financially beneficial to the entity making the request. Both require Commission authorization of service that the Commission is legislatively forbidden to authorize. The second request though less direct is the same as the first.

Our appellate courts have repeatedly held that a court is prohibited from doing indirectly what it may not do directly. Prudential Insurance Co. of America v. Powell, 217 N.C. 495, 8 S.E.2d 619 (1940). Moreover, our courts have also held that "A trial court must have subject matter jurisdiction over a case in order to act in that case." State v. Reinhardt, 183 N.C.App. 291, 292, 644 S.E.2d 26, 27 (2007). "Where jurisdiction is statutory and the Legislature requires the Court to exercise its jurisdiction in a certain manner, to follow a certain procedure, or otherwise subjects the Court to certain limitations, an act of the Court beyond these limits is in excess of its jurisdiction." Eudy v. Eudy, 288 N.C. 71, 75, 215 S.E.2d 782, 785 (1975), *overruled on other grounds by* Quick v. Quick, 305 N.C. 446, 290 S.E.2d 653 (1982).

In the instant case, the Commission stands in the role of a court. It is clear that the statute authorizes the Commission to permit CLPs to serve in ILEC territories. TWCIS (NC) has dutifully applied for such relief in one portion of its petition. In due course, the Commission will act upon that portion of the petition. In this portion of the action, TWCIS (NC) has petitioned this Commission to allow it to serve in TMC service territories. The Public Utilities Act does not permit the Commission to authorize TWCIS (NC) the CLP to provide service in TMC service areas. By this action, TWCIS (NC) seeks Commission permission to provide service in the forbidden area. The Commission may not directly or indirectly authorize service in this area because to do so is expressly forbidden by statute. Utilities Commission v. Merchandising Corp., 288 N.C. 715, 722, 220 S.E.2d 304, 309 (1975). If the Commission authorizes such service either directly or indirectly, it would be acting without subject matter jurisdiction. Any order issued to that effect would therefore be a legal nullity. Boseman v. Jarrell, 364 N.C. 537, 704 S.E.2d 494 (2010). See also In re T.R.P., 360 N.C. 588, 593, 636 S.E.2d 787, 792 (2006) (where the Supreme Court held that the court must have subject matter jurisdiction over the nature of the case and the type of relief sought in order to decide a case.) Emphasis Added.

Fourth, under North Carolina law, the Commission's jurisdiction over and responsibility for TWCIS (NC)'s operations is limited to TWCIS (NC)'s certificated[1] and regulated public utility operations; Commission authority does not extend to other TWCIS (NC) operations. The issuance of a CPCN to TWCIS (NC) does not expand the role of the Commission in this regard to TWCIS (NC)'s non-Commission regulated operations inside TMC service areas. As our Supreme Court has stated, the issuance of a certificate does not transform an ordinary business into a public utility, so as to entitle its operator to the rights of a public utility, or to so impose upon him the duties and limitations of a public utility. Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257, 267-268, 148 S.E.2d 100 (1966). Utilities Commission v. Carolina Telephone and Telegraph Co., 267 N.C. 257, 148 S.E.2d 100 (1966); Utilities Commission v. Southern Bell, 326

[1] G.S. 62-2(b) in pertinent part states that "authority shall be vested in the North Carolina Utilities Commission to allow competitive offerings of local exchange, exchange access, and long distance services by public utilities defined in G.S. 62-3(23)a.6 and certified in accordance with the provisions of G.S. 62-110…" Emphasis added. This language expressly refutes the position that the Commission has authority over all public utilities; the Commission regulates "certified" public utilities. TWCIS (NC) is not certified in TMC areas.

N.C. 522, 391 S.E.2d 487 (1991). This principle has been codified in law in G.S. 62-3(23)d. which in pertinent part provides: “If any person conducting a public utility shall also conduct any enterprise not a public utility, such enterprise is not subject to the provisions of this Chapter.” This principle is also consistent with the declaration of policy found in G.S. 62-2(b) which states that “[n]othing in this Chapter shall be construed to imply any extension of Utilities Commission regulatory jurisdiction over any industry or enterprise that is not subject to the regulatory jurisdiction of said Commission.”

The regulatory effect of this principle is best exemplified by the Commission’s treatment of AT&T. AT&T provides local exchange service in North Carolina pursuant to its CPCN. AT&T’s local exchange service is regulated by the Commission. AT&T’s wireless service is not. The fact that the Commission has issued a CPCN authorizing AT&T to provide local exchange service in North Carolina does not authorize the Commission to regulate its wireless enterprise even though it meets the technical definition of a public utility. Wireless service is not a legislatively approved, Commission certificated regulated service. Thus, in accordance with previously enunciated principles, the Commission has no jurisdiction to regulate un-certificated and unapproved telecommunications services.

The services provided by TWCIS (NC) in TMC territories are not legislatively authorized, Commission-approved and/or Commission-regulated “public utility” CLP operations under the provisions of Chapter 62.[1] Instead, these “public utility operations” are authorized and presumably regulated by some other entity. The responsibility for determining whether the entity offering these non-Commission regulated services should be designated as an ETC would ultimately fall to the agency or authority that authorizes services in the TMC areas and not to the Commission. This is precisely the result that the Commission reached in Docket Nos. P-100, Sub 133c, Order Granting Waivers and Designating Carriers, (December 15, 1997) and P-100, Sub 133c, Order Granting Petition, (August 28, 2003) respectively.

In the December 15, 1997 Order, the Commission referred the TMCs’ ETC designation request back to the NCREA, i.e., the agency that authorizes TMCs to provide service in those areas. In the August 28, 2003 Order, the Commission determined that commercial mobile radio service provider’s (CMRS) ETC designation requests should be determined by the FCC, the agency authorizing CMRS service in North Carolina rather than the Commission, an agency that had no jurisdiction to authorize CMRS service in North Carolina. Also, in Docket No. P-100, Sub 133e, (August 14, 2008), Order Seeking Comments and Dismissing Petition as to TMCs, a CMRS provider sought the Commission’s concurrence in redefining TMC service areas. The Commission refused to consider the concurrence request and referred the provider to the NCREA. In doing so, the Commission observed that it “is the relevant state commission only as to those entities over which it has jurisdiction,” and that it had no regulatory jurisdiction over CMRS providers. This is identical to the circumstances presented by the case at bar. That is, the “entity” providing service in these areas of the State is doing so with the blessing of the FCC and/or the NCREA and/or, at the very least, some unidentified source. In such circumstances, the FCC, the

[1] In TWCIS (NC)’s CLP application, it requested authorization to serve in ILEC territories. The CLP certificate authorizes it to serve in ILEC territories. Docket No. P-1262, Sub 0.

NCREA or the unidentified source, and not the Commission, will likely have jurisdiction to make the ETC designation.

Fifth, even if one were to assume that the service being rendered in the TMC territories was "Commission-regulated public utility" service, the Commission could not grant TWCIS (NC), the CLP, the relief that it desires, i.e., an ETC designation in TMC service territories, because TWCIS (NC)'s stated goal for seeking this ETC designation is to allow it to compete with TMCs for customers currently being served by those TMCs. As noted above, the text and the context of the Public Utilities Act is clear. The General Assembly directed the Commission not to authorize CLPs to compete with TMCs for customers in areas served by TMCs. It made its intentions clear in this regard by restricting the Commission's ability to certify and/or authorize TWCIS (NC) to provide services in those areas.

The General Assembly also restricted the Commission's ability to engage in the kind of inquiry that is necessary to determine if the public interest would be served by allowing the requesting entity to serve by adopting the provision in (f3) which states that "the provisions of subsection (f1) of this section shall not be applicable to areas served by telephone membership corporations…" Pursuant, to G.S. 62-110(f1), the Commission is authorized:

> …,following notice and an opportunity for interested parties to be heard, to issue a certificate to any person applying to provide local exchange or exchange access services as a public utility as defined in G.S. 62-3(23)a.6., without regard to whether local telephone service is already being provided in the territory for which the certificate is sought, provided that the person seeking to provide the service makes a satisfactory showing to the Commission that (i) the person is fit, capable, and financially able to render such service; (ii) the service to be provided will reasonably meet the service standards that the Commission may adopt; (iii) the provision of the service will not adversely impact the availability of reasonably affordable local exchange service; (iv) the person, to the extent it may be required to do so by the Commission, will participate in the support of universally available telephone service at affordable rates; and (v) the provision of the service does not otherwise adversely impact the public interest.

By the adoption of (f3), the General Assembly instructed the Commission to engage in this type inquiry in all instances in which a person seeks to provide CLP service except when the person seeks to provide CLP service in "areas served by telephone membership corporations…" In TMC areas, the Commission does not have jurisdiction to determine if the CLP's request to enter these areas is in the public interest. Yet, by federal law, that is precisely the inquiry that the Commission must engage in to determine if a requested ETC designation is "consistent with the public interest, convenience, and necessity". 47 U.S.C. 214(e)(2). Until this restriction is repealed or replaced by the General Assembly, the Commission is bound by it and the Commission cannot engage in the type of inquiry that is necessary to determine if the convenience and necessity would be served by designating TWCIS (NC) as an ETC in TMC service areas.

Additionally, the Majority suggests that any jurisdictional limitations with respect to the authority of this Commission to designate TWCIS (NC) as an ETC for Lifeline-only subsidy eligibility have been superseded by federal law and orders. In essence, the Majority argues that the federal law and orders of the FCC have preempted any jurisdictional restriction that the General Assembly has adopted that would impair the Commission's ability to designate TWCIS (NC) as an ETC in TMC areas. The Majority's argument is noteworthy for three reasons.

First, TWCIS (NC) did not raise this issue in its Petition or its Reply Comments. In its comments, the Public Staff cited G.S. 62-110(f)(3) in support of its contention that this Commission does not have jurisdiction to make an ETC designation in these circumstances. In its response, TWCIS (NC) acknowledged the Public Staff's citation and made various arguments to rebut the Public Staff's contentions. It did not, however, argue that G.S. 62-110(f)(3) had been preempted by federal law. Under North Carolina law, federal preemption is an affirmative defense. Richardson v. Bank of America, NA, 182 N.C. App. 531, 631 S.E. 2d 410(2007). As an affirmative defense, preemption must be pled or it is waived. Id. This argument has therefore been waived and the Majority may not resurrect it in support of its decision.

Second, in oral argument, counsel for TWCIS (NC) conceded that Section (f)(3) has not been preempted. See T. p. 112, lines 3-21. Third, this argument flies in the face of the actions taken by Congress and the FCC which acknowledge that states may indeed have carrier and/or territorially based jurisdictional limitations which prevent them from exercising jurisdiction on ETC matters. See In the Matters of the Federal State Joint Board on Universal Service Promoting Deployment and Subscribership in Unserved and Underserved Areas, 15 FCC RCD 12208, 12264, P. 112 (2000). (Designation Order).

In the Designation Order and Section 214 of the Telecommunications Act, when confronted with such limitations, Congress' and the FCC's intent was not to preempt jurisdictional limitations imposed by state law; nor was it their intent to require states to make such designations. Instead, Congress and the FCC adopted a process whereby carriers could pursue an ETC designation from the FCC if a state has jurisdictional prohibitions that would prevent a state commission from making such a designation. TWCIS (NC) has acknowledged as much in its pleading by stating: " should the Commission refuse to fully implement the service area proposed by TWCIS (NC), TWCIS (NC) would be forced to seek relief with respect to these areas from the FCC under Section 214(e)(6)." TWCIS (NC) Reply Comments, p. 15. By its actions here today, the Majority has veered from the path expressly authorized by the federal authorities and state law and cobbled together a decision based mainly on its belief as to what the Commission's jurisdiction should be, and not what it is.

The Majority's argument is founded upon its determination that the territorial restrictions and the ancillary jurisdictional restrictions attached thereto in (f)(3) violate the Supremacy Clause of the United States Constitution and are therefore preempted.[1] While this may ultimately prove to be true, an administrative agency such as this Commission has no authority to make this constitutional determination. See In re Central Telephone Company, 167 N.C. App. 14, 25, 604 S.E.2d 680, 686 (2004). In North Carolina, constitutional determinations of this sort are the

[1] TWCIS (NC) did not contend in its pleadings that the Commission's authority in G.S. 62-110(f)(3) has been preempted by federal law.

exclusive province of the judiciary. Utilities Commission v. Carolina Utility Customers Association, 336 N.C. 657, 446 S.E. 2d 332 (1994).

Section 253 of the Telecommunications Act of 1996 allows the FCC to preempt state law when it conflicts with the Act. [1] Section 253 specifies the process that the FCC must follow to have a state statute preempted. Neither the Company nor the majority has cited any instance in which the FCC, in accordance with this law, has determined that Subsection (f)(3) violates the Supremacy Clause and is thus preempted by federal legislation. Nor have the Majority or the Company cited to any decision by a court and/or the FCC that the territorial restriction imposed by Subsection (f3) is unconstitutional and preempted by federal law. For a court and/or the FCC to do so, either or both would have to overcome the presumption generally applied by courts disfavoring preemption in fields that the states traditionally regulate such as the intrastate provision of telecommunications and to find that the General Assembly intended to prohibit TWCIS (NC) from providing service in TMC areas. Waldburger v. CTS Corp., 723 F.3d 434 (4th Cir. 2013). The court and/or the FCC would also have to overcome the presumptions that a law enacted by the General Assembly is presumed to be constitutional and that a law that can be subject to two interpretations, one that is constitutional and another that is not, must be interpreted in a manner that sustains the constitutionality of the statute.

We do not believe that either the courts or the FCC would determine that Subsection (f)(3) of the Public Utilities Act would or should be preempted based upon the facts of this case. In our view, Subsection (f)(3) is subject to two interpretations, one that is constitutional and a second one which is not. If the statute is viewed only as a limitation of the Commission's jurisdiction over CLPs in TMC areas, it is constitutional and not subject to preemption because it would not preclude CLPs from serving in those territories with the permission of another state agency, the NCREA. Only if (f3) is viewed as an absolute bar to telecommunications service providers being able to serve in those areas, would it be unconstitutional and subject to preemption. The latter interpretation is only possible if the court or the FCC determines that the Commission is the only state authority with jurisdiction under North Carolina law to allow an entity such as TWCIS (NC) to serve in TMC areas. TWCIS (NC) and the Majority have chosen to advance and accept only this interpretation despite evidence presented in this proceeding that TWCIS (NC) has previously sought NCREA approval to serve in TMC territories by requesting the approval of interconnection agreements between TWCIS (NC) and numerous TMCs.

Interconnection agreements are a key component of service and are required by the same Telecommunications Act which allows TWCIS (NC) to seek an ETC designation from a state commission. NCREA review and approval should not be possible if the Commission has exclusive regulatory jurisdiction over CLPs in TMC areas. Yet, in this proceeding, TWCIS (NC) has argued that the NCREA is the appropriate state commission to authorize and approve this type service

[1] Section 253 of the Telecommunications Act states that "No state or local statute or regulation, or other state or local requirement, may prohibit or have the effect of prohibiting the ability of any entity to provide any interstate or intrastate telecommunications service." 47 U.S. C. 253(a). Section 253(d) authorizes the FCC to preempt a state from enforcing any such statute "after notice and public comment." See 47 U.S.C. 253(d). See footnote 21, Watters v. Wachovia Bank, 550 U.S. 1, 127 S. Ct. 1559 (2007). In this instance, we are unaware that the FCC has notified the State of North Carolina that it contends that the statute violates Section 253; the State has not been requested to submit comments as to this contention. Certainly, neither the Petitioner nor the Majority has cited evidence of either occurrence.

arrangement. In our view, this is strong evidence that the Commission does not have exclusive regulatory authority over CLP service in those TMC areas and that (f3) does not preclude TWCIS (NC) from serving in those areas. Moreover, we note that the NCREA has advocated in this proceeding that it indeed does have such authority and would exercise such authority with undue dispatch if TWCIS (NC) filed a petition with it requesting an ETC designation in areas served by TMCs. Again, we view this as strong evidence that the General Assembly did not exclude TWCIS (NC) from serving in those areas by adopting (f3). While we cannot with any certainty predict the decision of another tribunal, we can and do observe that the facts cited above could lead a court or the FCC to conclude that the North Carolina Commission is not the only agency that has jurisdiction to authorize services by TWCIS (NC) in TMC areas. Under those circumstances, Subsection (f)(3) is constitutional and cannot be preempted.

At this stage of the instant proceeding, neither the courts nor the FCC have declared that Subsection (f)(3) is preempted by the federal law and constitution. Until that is done and the matter is thoroughly and completed vetted by a duly constituted court and/or the FCC, or the General Assembly provides direction to the contrary, this Commission must presume that the statute is constitutional and give it the effect that the General Assembly intended. In oral argument, TWCIS (NC) conceded that this proposition is correct as a matter of law. See Tr. pp. 112, lines 3-21. Despite this concession, the Majority states that "TWCIS (NC) has a right to serve within North Carolina pursuant to its July 24, 2003 CPCN. It has a right to serve within the TMC study area pursuant to the federal statutes and orders. In effect, the federal statutes and orders augment TWCIS (NC)'s authority under its CPCN and supersede any limitations G.S. 62-110(f)(3) might otherwise have imposed on TWCIS (NC)'s service within TMC study areas boundaries and, specifically, with respect to the authority of this Commission to designate TWCIS (NC) as an ETC for Lifeline-only subsidy eligibility". Majority Opinion p. 11. Again, the Majority fails to cite to any statute or authority to support this contention.

This time, however, the Majority indicates in footnote 8 of its opinion that "Subsection (f2) which shields public utilities from competition that have less than 200,000 access lines has largely been superseded by the same federal acts and orders as those that have superseded Subsection (f3)." Majority Opinion p. 11. We discern that the Majority may be basing much of its argument on the FCC's decision in In re Hyperion of Tennessee, 14 F.C.C.R. 11064 (1999). In Hyperion, the FCC based its decision on the authority given to it in 47 U.S.C. 253 to preempt anticompetitive state laws. In that case, the FCC preempted Tennessee's enforcement of a restriction in law that did not allow a CPCN to be issued to a competitive carrier to compete with LECs that had less than 100,000 access lines and noted in dicta that North Carolina law G.S. 62-110(f)(2) which restricted the issuance of a CPCN in areas served by LECs with less than 200,000 lines *might* similarly be subject to preemption. In that regard, Hyperion provides limited insight as to what the FCC might ultimately decide on the question of whether G.S. 62-110 (f)(3) is or should be preempted by federal law because Hyperion is factually distinct from the case at hand. That is, in Hyperion, the Tennessee commission had sole authority to authorize service in the state. By contrast, in this case, the Commission has authorizing responsibility for certain carriers and certain areas of the state and the NCREA has responsibility for others. Thus, the Hyperion decision did not address the precise issue raised by the facts of this case.

In our view, Hyperion provides more valuable insight on the appropriate mechanism and processes for raising and deciding questions about federal preemption and the effect that an FCC decision would have on the authority of a state to certify a carrier to provide service if a state statute has been preempted. It is noteworthy that in Hyperion, as is currently the situation in the case before us, the carrier seeking to provide service in the restricted area was prevented from doing so by its inability to receive a CPCN from the state commission because of a state law prohibiting the state commission from issuing a CPCN in the affected areas. In that case, in contrast with this case, the carrier sought a CPCN and was denied the CPCN authorizing it to serve because of the state law. In arguing for the CPCN, the carrier asserted that the state statute prohibiting its service violated the federal law and was preempted. Its petition was denied by the state commission. The carrier thereafter petitioned the FCC to declare that the Tennessee statute was preempted by federal law.

As we noted in earlier portions of this dissent, TWCIS (NC) has not applied for a CPCN from this Commission to serve in TMC areas. TWCIS (NC) nevertheless admits to providing service in those TMC areas. TWCIS (NC) argues that it is able to do so because of some yet to be identified federal authority. This is a surprising assertion since intrastate provision of telecommunications service has traditionally been the province of the states. Moreover, this assertion suggests that this yet to be identified federal authorization somehow allows it to dispense with the certification requirement and serve TMC customers without applying for and receiving a CPCN from this Commission.

Hyperion holds otherwise and highlights the importance of the state certification process. In Hyperion, the provider, Hyperion, sought a CPCN to serve customers in the forbidden area and was denied. Hyperion successfully appealed to the FCC to have this denial overturned based on the preemption doctrine. It thereafter requested that the FCC require the state commission to issue a CPCN to allow it to serve. The FCC refused and required Hyperion to apply to the state commission to be able to serve in those restricted areas. The FCC did so despite ruling that the Tennessee Commission’s prior denial was invalid and in violation of federal law.

Thus, Hyperion stands for the proposition that a carrier may not serve in an area without a CPCN when a CPCN is required even if the law prohibiting the carrier from serving has been or may be preempted by federal law. Even under those circumstances, Hyperion holds that the carrier desiring to serve must still apply for a CPCN from the state commission before it can serve in those areas (where federal law requires reasonable entry to serve). Until a carrier makes such application, neither the FCC nor the state commission should authorize it to serve. If it serves and operates in the absence of such certification, it does so unlawfully. In the case now before the Commission, to the extent that TWCIS (NC) is providing or has provided services in TMC areas without Commission approval based upon its belief that the North Carolina law prohibiting such service is preempted by federal law, it has done so in violation of North Carolina law and the federal dictates exemplified by the Hyperion decision. This Commission should not therefore condone these unlawful actions by granting TWCIS (NC) an ETC designation. This, of course, assumes that this Commission has jurisdiction under state law over the entity providing such services.[1]

[1] The Majority cites two appellate cases, i.e., Utilities Commission v. Mackie, 79 N.C. App. 19, 338 S.E.2d 897 (1986) and Utilities Commission v. Buck Island, Inc., 162 N.C. App. 568, 592, S.E.2d 244 (2004), to suggest that the Commission has jurisdiction over a public utility even if the public utility did not apply for a CPCN before providing service to customers for compensation. We agree. The fact that the Commission has asserted jurisdiction over entities that were

In closing, we note that TWCIS (NC) cited federal laws and regulations, which define and permit a state Commission to designate a carrier as an ETC, and the Forbearance Order in support of its contention that this Commission has jurisdiction to make such a designation. The Majority opinion, for the most part, echoed these arguments. While the cited definitions, regulations and laws are indeed helpful in determining if an entity, person or board is a state commission and the federal definition of a common carrier does define common carrier, these federal laws and definitions provide little insight into the state commission's ultimate jurisdiction or ability to make an ETC designation. As stated in 47 U.S.C. 153(48), the jurisdiction of a state commission is determined under the laws of that state and not by federal law.

The same holds true for the Forbearance Order. The Forbearance Order has absolutely no bearing on the jurisdiction of a state commission. In the Forbearance Order, the FCC granted limited forbearance from the requirement of section 214(e)(5) of the Act and section 54.207(b) of the Commission's rules that the service area of an ETC conform to the service area of any rural telephone company serving the same area. The Forbearance Order excused TWCIS (NC) and other carriers from complying with the requirements in section 214(e)(5) which required carriers seeking an ETC designation in areas served by rural carriers to conform their service territories to those of the rural carrier. TWCIS (NC) acknowledges in its Petition, comments and argument, that it is not requesting a modification of any study areas in this action and this action was initiated pursuant to section 214(e)(2). Thus, the FCC's Forbearance Order does not shed any light on this Commission's authority to make the requested ETC designation. In fact, the FCC itself has recognized "that jurisdictional challenges relating to the authority of a state commission to designate certain carriers or classes of carriers on non-tribal lands derive almost exclusively from interpretations of state law." Designation Order, 15 FCC RCD 12208, 12264, P. 112 (2000).

Thus, for the reasons cited above, we conclude that the Commission does not have jurisdiction to designate TWCIS (NC) as an ETC in TMC service areas. We, therefore, respectfully dissent.[1]

\s_ToNola D. Brown-Bland___________
Commissioner ToNola D. Brown-Bland

\s_Bryan E. Beatty__________________
Commissioner Bryan E. Beatty

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providing services that fell within the Commission's purview without authorization does not vitiate this Commission's jurisdiction over those entities. In those instances, each of the entities contended that they were not public utilities. In this case, however, TWCIS is contending that it is indeed a public utility and that it does not need a CPCN to serve. TWCIS (NC)'s contention is contrary to the Mackie decision, where the Court of Appeals upheld the Commission's determination that Mackie was required to apply for and/or receive a CPCN because it was in fact a public utility.

[1] By this dissent, we express no opinion as the NCREA's jurisdiction to designate TWCIS (NC) as an ETC in TMC service areas.

DOCKET NO. P-100, SUB 137C

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER APPROVING ALL-SERVICES
Area Code Relief for North Carolina's	)	DISTRIBUTED OVERLAY OPTION TO
336 Numbering Plan Area	)	PROVIDE AREA CODE RELIEF

HEARD: Monday, June 23, 2014, at 7:00 p.m. and Tuesday, June 24, 2014, at 10:00 a.m. in the High Point Courthouse, High Point, North Carolina

BEFORE: Presiding Commissioner ToNola D. Brown-Bland, Commissioner Bryan E. Beatty, Commissioner Susan Warren Rabon, Commissioner Don M. Bailey, Commissioner Jerry C. Dockham, and Commissioner James G. Patterson

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FOR THE USING AND CONSUMING PUBLIC:

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BY THE COMMISSION: By this Order, and for the reasons set forth below, the Commission concludes that an all-services distributed overlay will be implemented in order to relieve area code 336, as the Commission has previously ordered with regard to area codes 704 and 919. The schedule for implementation of the overlay in the 336 area code will be as proposed by the North American Numbering Plan Administrator (NANPA), Neustar, Inc. (Neustar), as revised by the Joint Telecommunications Carriers[1] (JTC or Carriers) in their written Comments and testimony in this proceeding. Furthermore, seven-digit dialing across area code boundaries will be eliminated, and the Commission will require ten-digit dialing for local calls, extended area service (EAS) calls, and expanded local calling services (ELCS) calls placed across area code boundaries. Finally, the Commission directs NANPA that any numbering plan area (NPA or area code) it assigns for the 336 NPA distributed overlay shall not begin with "9-1".

BACKGROUND AND PROCEDURAL HISTORY

On September 7, 2000, Neustar filed its petition requesting that the Commission approve an industry recommendation of an all-services distributed overlay relief plan for the 336 NPA. The petition stated that the 336 NPA would reach exhaust by the fourth quarter of 2002. However, the implementation of numbering conservation measures, including thousands-block pooling in 2002, and a decrease in demand for numbering resources, extended the projected exhaust date. On January 5, 2001, the Commission issued its Order Requesting Comments and Scheduling Public Hearing on March 13 and 14, 2001, to consider the various relief alternatives for the 336 NPA, as proposed in the Initial Planning Document (IPD) and discussed by the industry. In compliance with that Order, comments were received from both the using and consuming public and the industry. On April 23, 2001, the North Carolina Telecommunications Industry and the Public Staff jointly filed the North Carolina Telecommunications Industry Task Force Proposed Order Approving Overlay Option to Provide Area Code Relief. The Task Force noted in its proposed Order that the Commission stressed that its intent was to prolong the service life of the 336 NPA by extensive conservation measures, such as thousands-block number pooling, and thereby postpone, for as long as possible, the use of the new area code as well as mandatory ten-digit local dialing.

On September 13, 2001, in Docket No. P-100, Sub 137, the Commission issued its Order Implementing Thousands-Block Pooling for the 336 Area Code, with the goal of delaying the implementation of area code relief for the 336 NPA for the foreseeable future.

Thereafter, on June 18, 2003, NANPA notified the Commission that that the 336 NPA was not projected to exhaust within the next five years. Furthermore, NANPA stated that,

> "according to the 2003 NRUF [Numbering Resource Utilization/Forecast] Analysis, the 336 projected exhaust date was pushed back to second quarter 2009. The extension of the projected exhaust is due in part to the implementation of

[1] The telecommunications and wireless carriers collectively referred to herein as the "Joint Telecommunications Carriers" are: BellSouth Telecommunications, LLC, d/b/a AT&T North Carolina (AT&T); Sprint Spectrum, L. P., and Sprint Communications Company L.P. (collectively, Sprint); T-Mobile South LLC (T-Mobile); Windstream Lexcom Communications, Inc., Windstream Communications, Inc., Windstream North Carolina, LLC, Windstream NuVox, Inc., US LEC of North Carolina, LLC (collectively, Windstream); North State Telephone Company, d/b/a North State Communications (North State); Carolina Telephone & Telegraph Company LLC, d/b/a CenturyLink, Central Telephone Company, d/b/a CenturyLink, CenturyLink Communications, LLC, and Mebtel, Inc., d/b/a CenturyLink (collectively, CenturyLink); Randolph Telephone Membership Corp.; and Cellco Partnership and its commercial mobile radio service provider subsidies operating in the state of North Carolina, d/b/a Verizon Wireless and MClmetro Access Transmission Services LLC, d/b/a Verizon Access Transmission Services (collectively, Verizon).

> thousands block pooling in February of 2002 and a continued decrease in demand for numbering resources."

NANPA also stated that pursuant to industry guidelines, the relief petition could be rescinded by the Commission or at least two industry members. As a result of the updated information provided by NANPA, the Commission took no action at that time.

On June 25, 2004, NANPA further notified the Commission that, according to the 2004 NRUF Analysis, the 336 projected exhaust date was expected to be second quarter 2010. Thus, in accord with industry guidelines, NANPA stated that the relief petition could be rescinded by the Commission on its own motion, or by at least two industry participants. Again, the Commission took no action as a result of the updated information provided by NANPA.

On July 22, 2013, NANPA filed a letter notifying the Commission that the projected exhaust date for the 336 NPA code had been revised to second quarter 2016. NANPA also provided an update of the four service alternatives to provide numbering relief to the 336 NPA included in the original IPD: (1) an all-services distributed overlay (alternative number one); (2) a geographic split which encompasses the Winston-Salem, Greensboro, and High Point rate centers, creating a circular geographic area (alternative two); (3) a geographic split with the boundary line following rate center boundaries in a northeastern to southwestern direction, placing the High Point rate center to the west of the line and the Summerfield, Monticello, Reidsville, Gatewood, and Ruffin rate centers to the east (alternative three); and (4) a geographic split with the boundary line following the rate center boundaries in a northeastern to southwestern direction, placing High Point rate center on the eastern side of the line and the Summerfield, Monticello, Reidsville, Gatewood, and Ruffin rate centers on the western side (alternative four). Attached to NANPA's letter were geographical maps depicting each alternative and their projected exhaust dates. NANPA went on to state that it recently released the April, 2013 NRUF, an NPA Exhaust Analysis reflecting actual data as of December 31, 2012, and the industry's projected demand for numbering resources. NANPA further stated that under its federal contract as numbering administrator, it is required to begin relief planning for area codes 36 months prior to the projected exhaust. Accordingly, the July 22, 2013 filing was made to update the evidentiary record and to renew NANPA's request that the Commission approve the industry's recommendation of an all-services distributed overlay relief plan for the 336 NPA.

On January 21, 2014, the Commission issued an Order Requesting Comments and Scheduling Public Hearings to address area code relief for the 336 NPA. In the Order, the Commission permitted members of the public to file comments by February 28, 2014, and allowed the formal parties to the proceeding to file comments regarding the industry recommendation or any other proposal by February 28, 2014, and reply comments by March 14, 2014. The Commission further ordered local exchange companies (LECs) and competing local providers (CLPs) to send public notice as a bill insert, via US mail or electronically to their subscribers within the 336 NPA by February 28, 2014, and ordered AT&T and North State to take primary responsibility for assuring the publication of public notice in newspapers of general circulation throughout the affected area. The Commission also encouraged the telephone membership corporations to notify their customers.

On January 28, 2014, AT&T filed a Motion requesting that the Commission extend the time for carriers to comply with the customer notice requirements, public notice and hearing date established in the January 21, 2014 Order by no less than 60 days. In support of its Motion, AT&T stated that it could not issue the customer notifications required by the Order quickly enough for the notices to reach the customers in time to provide the customers with a meaningful opportunity to participate in the public comment cycle established by the Order. On January 29, 2014, Time Warner Cable Information Services (North Carolina), LLC filed comments in support of AT&T's Motion. On January 31, 2014, the Commission issued an Order Holding Docket in Abeyance. In that Order, the Presiding Commissioner found that good cause existed to extend the time for notice, reschedule the hearing dates, and hold all matters in abeyance pending further order of the Commission.

On March 11, 2014, the Commission issued its Order Establishing Procedures, Scheduling Hearing and Requesting Comments (Procedural Order). In the Procedural Order, the Commission rescheduled the hearings in this matter for June 23 and 24, 2014, in High Point. The hearings were scheduled to commence on the evening of June 23, 2014 at which time testimony and comments from members of the public would be received, and to continue on the morning of the next day, at which time the Commission would receive any additional testimony from members of the public, as well as testimony from the formal parties to the docket. The Procedural Order further set a deadline of June 10, 2014 for the filing of initial written comments, and June 17, 2014 for the filing of reply comments. The Procedural Order also required AT&T and North State to take primary responsibility, with the cooperation of the other carriers, for publication of the public notice. The Order also required LECs and CLPs with retail customers in the 336 NPA to transmit the notice to their customers by June 10, 2014 via bill insert, US Mail or electronically.

On June 10, 2014, the Public Staff, tw telecom of north carolina l.p. (TWTC), and the Joint Telecommunications Carriers filed initial written Comments. No party filed reply comments. At the hearings at the High Point Courthouse commencing on the evening of June 23, 2014, the Commission received testimony from one member of the public, Mr. Chester Ayeres. On the morning of the next day at the same location, the Commission heard live testimony from Thomas C. Foley on behalf of Neustar, and Robert Smith of AT&T on behalf of the Joint Telecommunications Carriers.

On July 24, 2014, the Joint Telecommunications Carriers and the Public Staff filed a Proposed Order in this docket as requested by the Presiding Commissioner at the close of the evidentiary hearing.

SUMMARY OF JUNE 10, 2014 COMMENTS AND TESTIMONY

NANPA − The Petitioner, NANPA, did not file written comments, but presented the testimony of Mr. Foley at the June 24, 2014 hearing. Mr. Foley testified that NANPA is the neutral third-party administrator of the North American Numbering Plan, pursuant to its contract with the Federal Communications Commission (FCC). Mr. Foley testified that NANPA began planning for relief of the 336 NPA in 1999, and on July 27, 2000, hosted an industry meeting in Greensboro, North Carolina for the purpose of presenting NPA relief alternatives to the industry and allowing the industry members to reach consensus on a relief plan to recommend to the Commission. Prior to the July 27, 2000 meeting, NANPA distributed an IPD which included the four relief alternatives for the 336 NPA, i.e., three geographic splits and a distributed overlay. Mr. Foley explained that the industry reviewed the pros and cons of the four alternatives and reached consensus to recommend that the Commission issue an order to approve the distributive overlay.

On September 7, 2000, NANPA filed a petition with the Commission on behalf of the industry notifying the Commission of the industry's consensus to recommend the overlay as its preferred method of relief for the 336 NPA. At the time that NANPA's original petition was filed, the 336 NPA was projected to exhaust in 2002. Mr. Foley further testified that the exhaust date kept being pushed back due to implementation of numbering conservation measures, such as thousands number block pooling, and some changes in the economy. NANPA ultimately filed three separate letters with the Commission on June 18, 2003, June 25, 2004, and July 22, 2013, notifying it of changes to the exhaust projections. At the time of the July 22, 2013 filing, the 336 NPA was projected to exhaust during the second quarter of 2016. Mr. Foley explained that because this date falls within the next three years, NANPA is required to initiate NPA relief. Mr. Foley further stated that because NANPA's original petition remains open, NANPA submitted the July 22, 2013 filing in order to notify the Commission of the new exhaust projection dates and updated projected lives of the four relief alternatives. Mr. Foley reiterated that by a consensus decision, the industry recommended that the Commission select an all-services distributed overlay, alternative one, as the method of relief for the 336 NPA, with the result that the new NPA code would be assigned to the same geographic area as the existing 336 NPA. Mr. Foley further testified that the all-services distributed overlay alternative has a projected life of 43 years, and that all existing customers would retain their original numbers and not be required to change their numbers. Mr. Foley concluded his testimony by stating that if an overlay is approved, pursuant to FCC regulations, customers would have to dial ten digits for all local calls within the area, that the new central office code assignments would be made from the new overlay area code beginning one month after mandatory ten-digit dialing begins, and that all toll calls would continue to be completed by dialing 1 plus ten digits.

Joint Telecommunications Carriers − In their June 10, 2104 written Comments, the Joint Telecommunications Carriers stated that they support NANPA's September 7, 2000 and July 22, 2013 filings; specifically, the JTC supported an all-services distributed overlay as the most equitable and practical alternative to area code relief for the 336 area code. An all-services overlay would minimize inconvenience to consumers and align with the ongoing nationwide trend of the overlay method being the preferred form of area code relief. The JTC's Comments stated that an overlay has several advantages over an area code split (the other alternative for area code relief), including less customer impact and fewer technical issues, and that unlike the overlay solution, an area code split would treat consumers who have a 336 telephone number in an inequitable manner. A split would require some customers to change the area code of their ten-digit phone number, thus requiring those customers to contact family, friends, and business associates in order to provide them with the new area code. In their Comments, the Carriers also stated that an area code split could place significant financial burdens on business owners and operators in the affected area by requiring them to update their company stationery, business cards, texting information, and Internet-related sites, and to contact all of their existing customers to inform them of a new business phone number. The Carriers' Comments further stated that as consumers become more and more attached to and identified by their telephone numbers, an area code split would be significantly more burdensome than it might have been just a few years ago. Also, experience shows that consumers easily adapt to ten-digit dialing on calls within the same area code as part of their routine calling patterns. The JTC Comments also stated additional benefits of overlays over splits were the avoidance of technical issues that carriers experience in complying with customers' local number portability requests, as well as other technical problems such as caller ID customer confusion, text and multi-media messaging completion, smart phone applications impacts, wireless phone reprogramming issues, and administrative number impacts.

In their Comments, the Carriers stated that while they generally support NANPA's proposed implementation schedule, they recommended certain modifications. In its September 7, 2000 filing, NANPA outlined a thirteen-month schedule for implementation of the recommended all-services distributed overlay, with implementation beginning immediately upon the issuance of a Commission Order. The Carriers stated that in implementing numerous overlays across the country, they have come to recognize that some flexibility is helpful in establishing the general thirteen-month implementation schedule, and accordingly, the JTC proposed to modify NANPA's schedule in order to provide for an initial six-month period that would be focused on customer education and network preparation, followed by six months of permissive seven- or ten-digit dialing and continued customer education. After the first twelve months, mandatory ten-digit dialing would begin and the first code activation from the new NPA would become effective after one month of mandatory ten-digit dialing. The Carriers stated that based on the industry's cumulative experience with overlay implementations nationwide, this modified schedule would provide adequate time for network preparation and customer education, leading to a smooth implementation of the overlay.

The Carriers concluded their June 10, 2014 Comments by repeating their recommendation from NANPA's September 7, 2000 filing that "seven-digit dialing across NPA boundaries be eliminated and that the Commission require ten-digit dialing for local EAS and ELCS calls placed across NPA boundaries."

During his testimony at the June 24, 2014 hearing, Mr. Smith reiterated the above points, and during cross-examination, stated that he reviewed most of the consumer comments filed in the docket, the great majority of which were in favor of an overlay. Mr. Smith further testified during cross-examination that the relief option that public witness Ayeres mentioned at the June 23, 2014 hearing, which would involve using the star and hashtag signs in the dialing pattern, would require significant switch reprogramming nationwide to implement. In response to a Commission question, Mr. Smith further testified that the primary lesson learned from implementation of the overlay involving the 919 area code was not to assign another code starting with a 9-1 due to the unintended situation of mistaken 911 calls to public-safety answering points in the affected area. However, Mr. Smith went on to testify that aside from that one unforeseen consequence, implementation of the overlay in the 919 NPA went smoothly.

TWTC − TWTC submitted written Comments on June 10, 2014 supporting the industry's recommendation of an all-services distributed overlay for relief in the 336 NPA. In its Comments, TWTC stated that although it would require ten-digit dialing, an area code overlay is the preferred solution. TWTC further stated that implementation of an overlay would allow current customers to retain existing telephone numbers as opposed to a geographic split, which would require nearly half of the consumers to change telephone numbers. TWTC noted that consumers have become accustomed to ten-digit dialing in mobile phone usage and in other geographic areas in which an overlay has been implemented. TWTC concluded by stating that the overlay alternative would be the least disruptive to the 336 NPA.

Public Staff − The Public Staff filed written Comments on June 10, 2014. In its Comments, the Public Staff stated its belief that the distributed overlay alternative would be the best option for providing number relief for the 336 area code. The Public Staff noted that unlike a geographic split, a distributed overlay would not force communities to be separated by an NPA boundary that would require a mixture of seven- and ten-digit dialing. The Public Staff stated that the three geographic split alternatives would divide at least four counties and create confusing mixtures of seven- and ten-digit local dialing. The Public Staff also observed that in contrast to the geographic split alternatives, a distributed overlay would not require customers to change their existing telephone numbers, and any future NPA relief could be more easily implemented without disruption or confusion. The Public Staff went on to note that the disadvantage of overlays as opposed to splits, i.e., mandatory ten-digit dialing being required between and within the old area code and the new area code, is mitigated in this instance due to the fact that each of the geographic split alternatives would require a significant increase in ten-digit dialing by customers for local calls to nearby areas separated by a different area code, and accordingly, the primary advantage of the geographic split alternatives would be diminished with regard to relief for the 336 NPA. The Public Staff further noted that the Commission has previously approved distributed overlays for the 704 and 919 NPAs, and the only significant implementation issue regarding these two distributed overlays was an increase in the number of users mis-dialing 911 when attempting to make a ten-digit dialed call in the 919 NPA overlay area. However, the Public Staff stated that as long as the new NPA for the 336 NPA distributed overlay does not start with “9-1,” this issue should not be experienced again in connection with a distributed overlay in the 336 NPA. The Public Staff concluded its written Comments by recommending that the Commission adopt the distributed overlay as the relief mechanism for the 336 NPA and that the assigned NPA for the 336 NPA distributed overlay not begin with “9-1.”

WHEREUPON, based on the foregoing and the entire record of evidence in this matter to date, the Commission makes the following

CONCLUSIONS

After careful examination of the evidentiary record compiled in this proceeding, the Commission concludes that the recommended method of numbering relief for the 336 NPA, alternative one, the all-services distributed overlay, is the best of the four possible methods of relief presented in this matter, and shall be adopted as the method of relief for the 336 area code. The Commission notes that no formal party and no member of the public opposed the overlay method at the June 23 and 24, 2014 hearings held in High Point. Moreover, as the Public Staff suggested at the hearing, of the ten written comments received from members of the public, only two opposed the overlay, and those two commenters’ opposition appeared to stem from misunderstandings of the dialing patterns required by implementation of an overlay. NANPA estimates that selection of an overlay for the 336 area code will prolong numbering resources for 43 years. The Commission also has taken into consideration the fact that the disadvantage of overlays as opposed to splits, namely, mandatory ten-digit dialing being required between and within the old area code and the new area code, is mitigated in this instance as each of the geographic split alternatives would require a significant increase in ten-digit dialing by customers for local calls to nearby areas separated by a different area code. Therefore, the Commission selects the overlay method because it is the most efficient, most effective, and least disruptive of the four relief alternatives presented.

The Commission notes that it has previously adopted an all-services distributed overlay as the method of relief for the 704 and the 919 area codes, and the only significant implementation issue associated with either of those two prior overlays was not the result of the overlay relief method itself, but instead, the unique circumstance of consumers mis-dialing the 919 NPA as 911. This issue can and should be mitigated by directing NANPA in this proceeding to forebear from assigning as an overlay code for the 336 NPA any code beginning with a "9-1."

Further, the Commission remains committed to conservation of numbering resources through the use of thousands-block number pooling in the 336 NPA.

IT IS, THEREFORE, ORDERED as follows:

1. That an all-services distributed overlay is hereby adopted to provide relief for the current 336 area code in North Carolina.

2. That the schedule for implementation of the all-services distributed overlay in the 336 area code will be as described herein and proposed by NANPA, as revised by the Joint Telecommunications Carriers. The schedule shall be filed in this docket for informational purposes within thirty (30) days of the date of this Order.

3. That the JTC shall file reports with the Commission biannually with the final report filed six months after mandatory dialing is implemented in order for the Commission to keep informed on the progress of the implementation of the new NPA. The format and content of the reports are at the discretion of the JTC, however, the Commission is interested in monitoring the activities and be informed on any issues related to the new NPA.

4. That seven-digit dialing across area code boundaries shall be eliminated, and ten-digit dialing for local, EAS, and ELCS calls placed across area code boundaries shall be required.

5. That NANPA is hereby directed that it shall not assign an NPA beginning with "9-1" for the 336 NPA all-services distributed overlay.

ISSUED BY ORDER OF THE COMMISSION.
This the _13th_ day of August, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

BY THE COMMISSION: On June 5, 2014, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 1, 2014, Access Rate Changes.

In its Motion, the Public Staff requested that the Commission order the incumbent local exchange carriers (ILECs) to file revised tariffs and that certain competing local providers (CLPs) file notarized affidavits regarding the rate revisions necessary to comply with implementation of the provisions set forth in Part 51, Subparts H and J of the Federal Communications Commission's (FCC's) November 18, 2011 Universal Service Fund (USF) / Intercarrier Compensation (ICC) Transformation Order by no later than June 16, 2014.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff believes should make an appropriate filing regarding its 2014 switched access rate changes. The Public Staff stated that, additionally, any carrier that is not listed in Appendix A, but whose status has changed from last year should also be required to make an appropriate filing.

On June 5, 2014, the Commission issued an Order Requesting Comments on the Public Staff's Motion. No party filed initial comments on the Public Staff's Motion.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission finds it appropriate to grant the Public Staff's Motion, however, ILECs and CLPs shall have until June 18, 2014 to make the required filings.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __11th__ day of June, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. T-100, SUB 90

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

BY THE COMMISSION: Docket No. T-100, Sub 90 is a generic docket that the Commission opened for the purpose of addressing certain issues that initially arose in Docket Nos. T-100, Sub 49 and Sub 69. In Subs 49 and 69, the Public Staff filed a motion to replace the informational booklet in the Commission's Maximum Rate Tariff No. 1 (MRT). On October 5, 2011, the Commission issued an Order requesting comments and reply comments on the Public Staff's motion. Based upon the comments and reply comments received, the Commission issued an Order on May 30, 2012, amending the informational booklet and approving the Moving 101 Booklet. On page 12 of that Order, the Commission took notice of comments offered by Outstanding Service Corp., d/b/a John's Moving & Storage (John's Moving) regarding levels of cargo insurance, warehouse/storage-in-transit, and other matters that the Commission found to be beyond the scope of the Sub 69 proceeding.

On January 18, 2013, an Order was issued in Docket No T-100, Sub 90, requesting comments on six issues raised by John's Moving in Sub 69. The six issues concerned: (1) Depreciated Value Protection; (2) Cargo Insurance; (3) Storage Insurance; (4) Storage Information; (5) Insurance Certificates; and (6) Workers' Compensation Insurance.

Based upon the comments and reply comments received, an Order was issued on December 31, 2013, ruling on certain insurance issues and referring remaining issues regarding (1) Depreciated Value Protection, (2) Cargo Insurance, and (3 and 4) Storage to a Working Group to be composed of representatives from the Public Staff, the North Carolina Movers Association (NCMA), and other interested parties, including any certificated household goods movers (HHG). Furthermore, the Working Group was directed to report its recommendations on these issues to the Commission within 120 days. On April 29, 2014, the Commission issued an Order granting an extension of time until May 30, 2014 to file the Working Group's Report.

On May 30, 2014, the Public Staff filed the Report of the Working Group. In addition to representatives from the Public Staff and the NCMA, the following certificated companies participated in the Working Group: College Hunks Hauling Junk and Moving; Horne Moving Systems, Inc.; John's Moving & Storage; Mather Brothers Moving Company, LLC; Ray Moving & Storage, Inc.; Steele & Vaughn Moving & Storage; and Two Men and A Truck of Charlotte.

ISSUE NO. 1 – DEPRECIATED VALUE PROTECTION (DVP)

The Commission referred this issue to the Working Group and requested it to:

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

The Working Group recommended that DVP be eliminated and that BVP be adopted as the replacement default valuation option. A summary of HHG operations provided by the Public Staff revealed that BVP is the overwhelming choice of shippers with a much lower number of shippers choosing FVP. The Working Group discussed whether FVP with deductibles should be offered. The majority of the Working Group, including the Public Staff, believe that, based upon a cost-benefit analysis, FVP with deductibles would not be in the shipper's best interest. The following example was offered to support the claim that the shipper is better off without a deductible:

> During a move, a box of china is dropped with damages totaling $400 to replace the broken items.
>
> With no deductible, a shipper can choose $40,000 of coverage and pays $300 for FVP. Cost of coverage is $300 (no deductible); shipper's cost to replace china is $0; so total cost to shipper is $300.
>
> With a $500 deductible, for 10,000 pounds a shipper receives $40,000 of coverage and pays $200 for FVP. Cost of coverage is $200, shipper's cost to replace china is $400, so total cost to shipper is $600.

The Working Group believes it is important that the shipper be fully informed as to the differences between BVP and FVP by using clean and simple language as reflected in the proposed changes to the Moving 101 Booklet, at Section VII, Two Types of Valuation, submitted with the Report. In summary, the Working Group proposed that Section VII of the Moving 101 Booklet be modified to reflect that there are two types of valuation, BVP and FVP, available for both weight/distance and hourly-rated moves. BVP is the lower level of value protection. It is provided at no cost and provides minimal protection; and if the shipper fails to select a valuation option, the default valuation is BVP.

In addition, the Working Group members discussed a possible increase in the $4.00/lb. minimum value for FVP, which has been in effect since November 1, 2001. Several carriers believe it is inadequate. The federal government uses $6.00/lb. as a minimum value for FVP. The Working

Group did not have a recommendation as to the appropriate minimum value for FVP but suggested the Commission may want to consider studying this issue in more detail in the future.

DISCUSSION AND CONCLUSIONS – ISSUE NO. 1

The Commission's MRT currently allows the carrier/mover to offer three types of valuation to the shipper: Basic Value Protection (BVP), Depreciated Value Protection (DVP), and Full Value Protection (FVP). In selecting a valuation option the shipper establishes: (1) the total value of their shipment; (2) how a carrier will resolve their claim for loss or damage to individual items; and (3) how a carrier will resolve their claim for catastrophic loss or damage to all of their items. Valuation is not insurance but is an agreement between a shipper and a carrier as to the total value of the shipment. The shipper selects the level of valuation; however, if the shipper does not do so, the current default valuation is DVP.

BVP provides minimum protection and is free to the shipper. The carrier's maximum liability will be $.60 per pound based upon the weight of any lost or damaged items. With DVP, the minimum value of the shipment will be $1.25 times the weight of the shipment. The cost to the shipper is $.50 per $100 of value. With FVP, the minimum value of the shipment will be $4.00 times the weight of the shipment, and the cost is $.75 per $100 of value. Both DVP and FVP allow the shipper to declare that its shipment has a greater value and to pay for that increased protection.

As previously mentioned, the Working Group recommended that DVP should be eliminated as a valuation option. As was noted in the December 31, 2013 Order, DVP is rarely used; determining the costs and age of damaged or lost items can be difficult and subjective; and the DVP option has been eliminated by several federal government agencies as a valuation option, specifically, the General Service Administration, the Surface Transportation Board, and the Department of Defense. Based upon a summary of HHG operations provided by the Public Staff, BVP is the overwhelming choice of shippers with a much lower number choosing FVP. Based upon the foregoing, the Commission concludes that DVP should be eliminated as a valuation option and that BVP should be adopted as the replacement default valuation option. Consequently, in the MRT, Section IV, Item 17, Depreciated Valuation Charges should be eliminated.

Regarding whether FVP with deductibles should be offered, input from carriers indicated some support for the option. However, the majority of the Working Group, including the Public Staff, stated that a cost-benefit analysis revealed that FVP with deductibles would not be in the shipper's best interest. The Commission concurs and concludes that FVP with deductibles should not be offered. The Commission recognizes, however, that any carrier may petition the Commission to revisit this matter in the future.

Although not directed by the Commission to do so, the Working Group discussed whether an increase in the $4.00/lb. minimum value for FVP was warranted. The current rate has been in effect since 2001, and several carriers believe it is inadequate. The federal government uses $6.00/lb. as its minimum value for FVP. However, no recommendation was made by the Working Group other than they did state that the Commission may want to consider this issue in more detail in the future. The Commission is of the opinion that the Working Group had ample opportunity to review this issue and to make any needed recommendations. The Commission finds and concludes that the $4.00/lb. minimum value for FVP should remain unchanged.

ISSUE NO. 2 – CARGO INSURANCE

The Commission referred this issue to the Working Group and requested it to:

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

The Working Group determined that the current requirements and limits for cargo insurance ($50,000) are adequate and do not need to be changed. They further noted that based on a summary of the 2012 Annual Reports submitted by HHG carriers, approximately 16% of moves were transported under FVP and that even fewer moves involve shippers requesting coverage or declared amounts in excess of $50,000 for the total value of their shipment. The Working Group is of the opinion that the carrier is responsible for obtaining the necessary cargo insurance coverage in order to ensure that shipments are adequately covered.

Regarding the cost of additional insurance, the Working Group believes that carriers should not be permitted to pass-through the cost of any additional cargo insurance purchased for a particular move, as the cost of FVP sufficiently covers the additional declared amount of the shipment. The Working Group did recommend adding language to the Moving 101 Booklet to inform shippers of the requirements and to suggest that shippers request written verification of insurance coverage if desired. The proposed language was included with the Working Group's Report in the Moving 101 Booklet in Section I, Introduction and Section VII, Two Types of Valuation.

DISCUSSION AND CONCLUSIONS ISSUE NO. 2

Commission Rule R2-36 currently requires household goods carriers to maintain a minimum of $50,000 cargo insurance coverage. The Working Group was requested to determine if this coverage amount should be changed or remain the same. They determined that the current limits for cargo insurance coverage are adequate. The Working Group also stated that only a small percentage of moves involve shippers requesting coverage of declared amounts in excess of $50,000 for the total value of their shipment. For those higher declared amount shipments, the Working Group believes that the carrier is responsible for obtaining the additional insurance necessary to insure adequate coverage and that the cost should not be passed on to the shipper.

The Working Group recommended adding language to the Moving 101 Booklet to inform shippers of the requirements and to suggest that shippers request written verification of insurance coverage if desired.

The Commission concludes that all carriers are responsible for obtaining any additional insurance necessary to insure adequate coverage on all shipments and that no additional cost should be passed on to the shippers. The Commission further concludes that the current $50,000 minimum amount of cargo insurance coverage should remain unchanged and that the following language be should be added to the Moving 101 Booklet:

> *The Commission requires movers to carry a minimum amount of $50,000 for general liability insurance and a minimum amount of $50,000 for cargo insurance. If you believe that your shipment has a value greater than the $50,000 minimum amount of insurance coverage required by the Commission, you may want to request written verification of additional coverage from your mover to ensure your shipment will be adequately covered.*

ISSUE NOS. 3 AND 4 – STORAGE

The Commission referred this issue to the Working Group and requested it to:

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

(g) Recommend the appropriate time period and/or date(s) for any such proposed changes to be implemented.

The Working Group agreed that only carriers that own their own warehouses or that have long-term lease agreements at public warehouses (not a "mini-storage") should provide SIT services. A carrier that does not own its own storage facility and/or warehouse or does not have a long-term lease agreement for warehouse space should release the shipment into the care of the shipper and should not be permitted to store the shipment in the carrier's name.

The Working Group also determined that a carrier that offers SIT should possess adequate insurance coverage as determined by a reputable insurance company licensed to do business in North Carolina, and that the carrier should be required to file proof of insurance coverage with their Annual Reports. This will allow the Commission and the Public Staff to determine which carriers offer SIT and to confirm that those carriers have adequate insurance coverage for SIT shipments.

Regarding additional costs for SIT insurance, the Working Group believes that the cost should not be passed on to the shipper. However, the Working Group did determine that calculating "Extended SIT Valuation" based on 15% of the cost of full value protection per month would be more appropriate than charging 10% of the monthly storage fee, which is determined by the weight of the shipment as allowed in the MRT in Section IV, Item 17. To support this claim, it provided the following examples:

> Currently, "Extended SIT Valuation" for a shipment weighing 10,000 lbs. is calculated by the weight of the shipment x $4.65 (rate) per 100 lbs. = $465 x 10% = $46.50 per month. (MRT, Section IV, Item 13 Storage-In-Transit Rates; 10% from Item 17)
> Proposed calculation with 15%: 10,000 lbs. shipment x $4.00 per pound = $40,000 x .75 per $100 = $300 x 15% = $45 per month. (MRT, Section IV, Item 18 Full Value Protection)
>
> If, however, the shipment has a declared value of $75,000, the calculation would be $75,000 x .75 per $100 = $562.50 x 15% = $84.37 per month. The declared value is more related to the cost of valuation than the weight of the shipment.

Changing the method and percentage of calculation for SIT storage would keep this charge approximately the same for the vast majority of moves, while recognizing the risk to the carrier of storing more valuable shipments.

The Working Group also discussed SIT transportation rates and agreed that there is very little correlation between these rates and other current transportation rates. The Working Group proposed that the Commission approve an increase in the SIT transportation rates to a level that basically represents one-half of the MRT Section III weight/distance rates calculated for moves of less than 35 miles. This calculation, as shown in the Working Group's Report in Appendix A, presents a more logical link between SIT transportation rates and MRT Section III rates. The Working Group stated that SIT basically represents one-half of a move and therefore one-half of the MRT Section III rates. The Working Group does not believe it would be appropriate to change SIT transportation rates to hourly rates because SIT shipments are inventoried and weight based, including monthly storage fees. Appendix A attached to the report reflected the proposed changes between SIT transportation rates and MRT Section III weight/distance rates.

Regarding carriers providing shippers an SIT informational document/form, the Working Group believes it would not be practical for shippers to receive another moving document. Instead, it was agreed that all carriers providing SIT services should be required to disclose the physical location of the storage facility on the bill of lading and ensure that all rates and charges are accurately noted on the estimate form and bill of lading. The Working Group also believes that noting this information in the Moving 101 Booklet is more advantageous and helpful for the shipper rather than requiring the completion of another document.

DISCUSSION AND CONCLUSIONS – ISSUE NOS. 3 AND 4

There are two types of storage in the moving industry: storage-in-transit (SIT) and permanent storage. Shipments held by the carrier in the warehouse of the carrier or its agent for storage, pending further transportation, and stored for 180 days or less are considered SIT. If the storage is longer than 180 days, it is considered permanent storage. The Commission only has jurisdiction over SIT.

The Working Group was requested to develop SIT insurance requirements for two scenarios: (1) shipments placed in a storage facility owned by the carrier, and (2) shipments placed in a storage facility not owned by the carrier, such as a public mini-storage facility.

MRT Section I, Rule 48 (Storage-In-Transit), subsection (A) states:

> "Storage-in-transit of shipments covered by this tariff is the holding of the shipment in the warehouse of the carrier or its agent for storage, pending further transportation, and will be effected only at the specific request of the shipper. For the purpose of this rule, a carrier may designate any warehouse to serve as its agent."

The Working Group believes that only carriers with warehouses or carriers with long-term lease agreements at public warehouses (not a mini-storage facility) should be allowed to provide SIT services. Currently MRT Section I, Rule 48 (A) does not make this distinction but allows the carrier to "designate any warehouse to serve as its agent". The Commission agrees with the Working Group's assessment and concludes that only those carriers who own a warehouse or have a long-term lease agreement with a public warehouse can provide SIT. In both of these situations, the carrier will have control over the SIT shipment.

Regarding insurance requirements for SIT shipments, no specific insurance requirements were recommended by the Working Group. Instead, they suggested that adequate coverage should be required and that the carrier should submit proof of insurance with its Annual Report. The Commission is of the opinion that this filing requirement will allow greater oversight for those carriers who provide SIT and concludes that carriers providing SIT should be required to file proof of insurance with their Annual Reports. In addition, no insurance costs for SIT will be passed on to the shipper.

Based upon the foregoing, the Commission concludes that MRT, Section I, Rule 48 (A) should be amended as follows:

> *Storage-in-transit of shipments covered by this tariff is the holding of the shipment in the warehouse owned by the carrier or in a public warehouse with which the carrier has a long-term lease agreement for storage, pending further transportation, and will be affected only at the specific request of the shipper.* ***Carriers providing storage in transit are required to file proof of insurance for such storage with their Annual Report****.*

The Commission also requested that the Working Group develop an SIT information document/form for carriers to complete and provide to shippers who require SIT. The Working Group does not believe that another separate document with SIT information is needed. The carrier can provide the physical location of the storage facility on the bill of lading and ensure that all rates and charges are accurately noted on the estimate form and bill of lading. Also, providing this related information in the Moving 101 Booklet would be more advantageous and helpful. The Moving 101 Booklet at Section VI, Storage Options, the last sentence in the first paragraph is worded as follows: "Be sure you know the location of the warehouse or the warehouse of the mover's agent where your goods are stored." The Commission is of the opinion that this last sentence in the first paragraph should be slightly modified as follows:

> ***Be sure you know the location of the warehouse where your goods are stored.***

Additionally, the Commission agrees with the Working Group and concludes that the following language should also be inserted in the first paragraph of the Moving 101 Booklet, Section VI. Storage Options as the last sentence:

> ***Also, you may want to request written verification that the mover has adequate insurance coverage while your shipment is in storage.***

The Working Group was also requested to review and develop any necessary revisions in MRT rates for pick-up and delivery of SIT shipments. Appendix A attached to the Working Group's Report reflected the proposed changes between SIT transportation rates and MRT Section III weight/distance rates. In support of its recommendation, the Working Group stated that there is very little correlation between these rates and other current transportation rates. The requested increase in the SIT transportation rates basically represents one-half of the Section III weight/distance rates calculated for moves less than 35 miles, i.e., SIT basically represents one-half of a move and therefore one-half of the Section III rates. The Working Group does not believe it would be appropriate to change SIT transportation rates to hourly rates because SIT shipments are inventoried and weight based, including monthly storage fees. After reviewing the documentation provided by the Working Group, the Commission concludes that the increase in SIT Transportation Rates is justified and should be adopted. The approved rates, reflecting MRT rate-rounding design, are those set forth in Appendix A attached to this Order.

Another methodology for calculating valuation charges on SIT shipments was also recommended by the Working Group. Section IV, Item 17 of the MRT presently states in part:

> "On shipments which also involve storage-in-transit, the following additional valuation charge will apply: For each storage period of 30 days or fraction thereof, the additional valuation rate of 10 percent of the applicable storage-in-transit rate provided for in Item 13." [Item 13, Storage-In-Transit Rates.]

As previously discussed, the Commission has determined that the MRT, Section IV, Item 17, Depreciated Valuation Charges should be eliminated from the MRT. The Working Group believes that calculating extended SIT valuation based on 15% of the cost of full value protection per month would be more appropriate than charging 10% of the monthly storage fee, which is determined by the weight of the shipment. They reasoned that changing the method and percentage of calculation for SIT storage would keep this charge approximately the same for the vast majority of moves, while recognizing the risk to the carrier of storing more valuable shipments. The Commission is of the opinion that the change in methodology for calculating valuation charges for SIT is appropriate and concludes that the proposed language contained in Appendix B Item 18 (F) attached to the Working Group's Report should be adopted as follows:

> *ON SHIPMENTS WHICH ALSO INVOLVE STORAGE-IN-TRANSIT, the following additional valuation charge will apply: For each storage period of 30 days or fraction thereof, the additional valuation rate of 15 percent of the full value protection rate provided for in Item 18. [Item 18, Full Value Protection.]*

Lastly, the Working Group recommended that all the proposed changes be implemented effective January 1, 2015. The Commission concurs and concludes that the proposed effective date is appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That Depreciated Value Protection (Section IV, tem 17) is deleted from the Maximum Rate Tariff No. 1 as a valuation option, and that Basic Value Protection shall be, and hereby is, adopted as the default valuation when a shipper does not select a valuation option.

2. That the current cargo insurance minimum of $50,000 remain unchanged and that the following language shall be added to the Moving 101 Booklet:

> The Commission requires movers to carry a minimum amount of $50,000 for general liability insurance and a minimum amount of $50,000 for cargo insurance. If you believe that your shipment has a value greater than the $50,000 minimum amount of insurance coverage required by the Commission, you may want to request written verification of additional coverage from your mover to ensure your shipment will be adequately covered.

3. That carriers holding a certificate of exemption from the Commission must own a warehouse or have a long-term lease agreement with a public warehouse prior to offering storage-in-transit. MRT Rule 48 (A) shall be rewritten as follows:

> Storage-in-transit of shipments covered by this tariff is the holding of the shipment in the warehouse owned by the carrier or in a public warehouse with which the carrier has a long-

term lease agreement for storage, pending further transportation, and will be affected only at the specific request of the shipper. Carriers providing storage in transit are required to file proof of insurance for such storage with their Annual Report.

4. That carriers holding a certificate of exemption from the Commission and offering SIT shall file proof of SIT insurance coverage with carrier's Annual Report.

5. That the increase in Section IV, Item 14, SIT Transportation Rates, as set forth in Appendix A attached to this Order shall be, and hereby are, approved effective January 1, 2015.

6. That the change in valuation charges on SIT shipments from the current 10% of monthly storage fee to 15% of the cost of Full Value Protection is hereby approved effective January 1, 2015 and that Section IV, Item 18 (F) shall be rewritten as follows:

On shipments which also involve storage-in-transit, the following additional valuation charge will apply: For each storage period of 30 days or fraction thereof, the additional valuation rate of 15 percent of the full value protection rate provided for in Item 18.

7. That the approved changes to the MRT and the Moving 101 Booklet[1] are set forth in Appendix B attached to this Order.

8. That all the changes adopted in this Order will become effective on and after January 1, 2015.

9. That copies of this Order shall be served by the Chief Clerk's Office to all carriers holding a certificate of exemption from the Commission, the Public Staff, the NCMA, and the Attorney General.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of October, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

[1] The changes are denoted by bold and italics.

MAXIMUM RATE TARIFF NO. 1

SECTION I – RULES AND REGULATIONS

RULE 3

SCOPE AND APPLICATION OF TARIFF

Subject to the rules and regulations contained in Section I, the rates and charges shown in Sections II, III, and IV are the maximum rates and charges to be assessed by all carriers governed by this tariff, for all movements of household goods within North Carolina. EXCEPTION: Section IV, Item 18 (Full Value Protection) includes rates which are not subject to negotiated discounts.

All carriers issued a certificate of exemption by the North Carolina Utilities Commission authorizing the intrastate transportation of household goods are required to use the forms in Section V of this tariff.

RULE 7

VALUATION

(A) As used in this tariff, the phrases, "released value", "declared value", "value declared by shipper", and "lump sum value" shall have the same meaning.

(B) On any shipment where the transportation charge is based on weight and distance and/or hourly rated movements pursuant to the provisions of this tariff, the carrier's maximum liability shall be either (1) ***$4.00*** times the actual weight (in pounds) of the shipment (constructive weight on hourly shipments-see Rule 29(B) (Basis of Weight)), or the declared lump sum value, whichever is greater; or (2) $.60 per pound for the actual weight of any lost or damaged article or articles, if the shipment has been expressly released by the shipper to such value per article. Unless the shipper expressly releases the shipment to a value ***equal to $4.00 for each pound of weight in the shipment or lump sum value declared by the shipper***, the carrier's maximum liability for loss and damage ***will not exceed $.60 per pound per article.***

(C) The released value must be shown on the bill of lading in the following form and must be initialed only by the person signing the bill of lading:

VALUATION: Shipper must initial the option selected.

______ Basic Value Protection. I release this shipment to a value of $.60 per pound per article.
______ Full Value Protection. I release this shipment to a value of $4.00 times actual weight in pounds of shipment or declared lump sum value of $______. (Declared value must be at least $4.00 per pound times weight of shipment.)
See attached “Addendum to Uniform Household Goods Bill of Lading.”

(D) If the shipper fails to make the entry required in subsection (C) of this rule, the shipment will be deemed released to ***$.60 per pound per article (Basic Value Protection)***.

(E) The released value and the carrier's maximum liability (whether or not loss or damage occurred from carrier negligence), as determined under this rule, shall apply to any claims resulting from the performance or failure to perform by carrier of any services, including accessorial services, which carrier has contracted to perform.

(F) Full Value Protection - See Section IV, Item 18.

RULE 27

BILL OF LADING

(D) Unless the shipper expressly releases the shipment to a value not exceeding $.60 per pound per article, the carrier's maximum liability for loss and damage shall be (1) the lump sum value declared by the shipper or (2) an amount equal to $4.00 times the actual weight in pounds for full value protection, whichever is greater. For these increased levels of liability, additional valuation charges as provided in Section IV, Item 18 (Full Value Protection) will apply. If the shipper wishes to avoid these additional charges, he must agree that if any articles are lost or damaged, the carrier's liability will not exceed $.60 per pound for the actual weight of any lost or damaged article or articles in the shipment.

RULE 48

STORAGE-IN-TRANSIT

(A) Storage-in-transit of shipments covered by this tariff is the holding of the shipment in the warehouse owned by the carrier or in a public warehouse with which the carrier has a long-term lease agreement for storage, pending further transportation, and will be affected only at the specific request of the shipper. Carriers providing storage in transit are required to file proof of insurance for such storage with their Annual Report.

[Subsections (B) through (H) remain unchanged.]

RULE 55

RATES APPLY ON AND ARE SUBJECT TO A MAXIMUM RATE AS FOLLOWS:

Shipments released to a value not exceeding $.60 per pound per article.
Shipments transported between all points in the State of North Carolina EXCEPT shipments moving under provisions and/or charges in Section II.
Rates apply without additional valuation charges when shipment is released to a value not exceeding $.60 per pound per article. When shipment is not released to a value not exceeding $.60 per pound per article or shipper declares a valuation on entire shipment, rates herein apply plus Valuation Charges named in Section IV, Item ***18***. Rates are in dollars and cents per 100 pounds applied to actual weight and include loading and unloading and the actual movement

or transportation of property from origin to destination. Rates do not include Additional Services and Charges detailed in Section IV.

SECTION IV – ADDITIONAL CHARGES AND SERVICES

ITEM 13

STORAGE-IN-TRANSIT RATES

SERVICE (Storage-In-Transit Rates)	PER	RATES (in dollars/cents)
Application subject to Rule 48. Subject to 1,000 pound minimum.		
STORAGE RATE (See Notes 1, 2, and 3)	100 lbs	4.65
CLIMATE CONTROLLED STORAGE RATE (See Notes 1, 2, and 4)	100 lbs	6.20
WAREHOUSE HANDLING RATE (See Note 1)	100 lbs	7.85

NOTE 1: Storage charges apply for each 30 days or fraction thereof each time storage-in-transit service is rendered. Warehouse handling charge applies once each time shipment is placed in storage-in-transit.
NOTE 2: For valuation charge applying on storage-in-transit shipments, see Item ***18***.
NOTE 3: Not applicable when climate control is required.
NOTE 4: Climate controlled storage means that adequate heating and air conditioning equipment is in place to maintain a temperature range of 60 to 85 degrees and humidity reading of no greater than 90% at all times.

ITEM 14

PICKUP OR DELIVERY TRANSPORTATION RATES TO APPLY ON STORAGE-IN-TRANSIT SHIPMENTS

SERVICE (Pickup or Delivery Transportation Rates)	PER	RATES (in dollars/cents)
Application subject to Rule 48, Storage-In-Transit. Subject to 500 pound minimum.		
500 to 999 lbs. incl. (Break point wt. 627 lbs)	100 lbs.	***33.30***
1,000 to 1,999 lbs. incl. (Break point wt. 1,648 lbs.)	100 lbs.	***22.25***
2,000 to 3,999 lbs. incl. (Break point wt. 3,587 lbs.)	100 lbs.	***17.40***
4,000 to 7,999 lbs. incl. (Break point wt. 7,492 lbs.)	100 lbs.	***14.55***
8,000 lbs. and over	100 lbs.	11.80

ITEM 17 DEPRECIATED VALUATION CHARGES - *Deleted*

ITEM 18

FULL VALUE PROTECTION

SERVICE ***(Full Value Protection – Subject to Rule 7 - Valuation)*** ***Applies to Weight/Distance and Hourly Moves***	***PER***	***RATES (in dollars/cents)***
Coverage is subject to $4.00 /lb. minimum or a higher value declared by the shipper	***100 lbs.***	***$0.75***

(A) When Full Value Protection is ordered in writing by the customer, carrier will guarantee either replacement of articles lost or damaged while in carrier's custody, reimbursement for full replacement cost (as determined by current market value), or repairs or the cost of repairs to damaged item(s) to the extent necessary to restore the item to the same condition as when received by carrier from the shipper. Actual replacement articles, if any, shall consist of articles of like kind and quality without deduction for depreciation.

(B) Carrier's maximum liability shall not exceed the released or declared value on the shipment or the full cost of repair to the damaged property, whichever is less. Carrier shall have the option of repair or replacement of damaged articles.

(C) All items which are replaced or for which the full current market value has been paid become the property of the carrier.

(D) Full Value Protection will be provided by carrier only if shipment is declared or released to a minimum valuation of $4.00 for each pound of weight in the shipment.

(E) The rate for Full Value Protection provided by the carrier will be $.75 for each $100.00 or fraction thereof, of released or declared value.

> ***EXAMPLE: Shipment valuation is calculated at the value of $20,335.00. Since $35.00 is a fraction of $100.00, the charge would be based on a valuation of $20, 400.00.***

(F) ON SHIPMENTS WHICH ALSO INVOLVE STORAGE-IN-TRANSIT, the following additional valuation charge will apply: For each storage period of 30 days or fraction thereof, the additional valuation rate of 15 percent of the full value protection rate provided for in Item 18.

(G) Protection under this item will not apply to specific articles or matched sets of articles which are valued at $3,000 or more, unless shipper puts carrier on notice in writing that such articles are included in the shipment.
NOTE: See Rule 7 (Valuation).

UNIFORM HOUSEHOLD GOODS BILL OF LADING

CARRIER'S NAME & ADDRESS
CARRIER'S TELEPHONE
CARRIER'S C#

CARRIER REFERENCE NO.

SHIPPER
COMPANY
STREET ADDRESS
CITY & STATE
TELEPHONE

AGREED LOAD DATE: ___________________________

I HAVE RECEIVED A COPY OF THE NCUC BROCHURE EXPLAINING MY RIGHTS.
SHIPPER'S SIGNATURE: ___________________________

______ **Exclusive Use** of a __________ cu. ft. vehicle (Minimum 1000 cu. ft.)
______ **Space Reservation** of _________ cu. ft. (Minimum 300 cu. ft.)
______**Expedited Service** of __________ miles

Shipment Moving at ___________ lbs
Actual Weight of ____________ lbs
Signature of Shipper or Agent:
____

NOTE: SHIPPER MUST INDICATE CHOICES MADE ON BOTH OF THE ITEMS SHOWN BELOW BY INITIALING THE APPROPRIATE LINE. (Estimates & Valuation)

ESTIMATES: Shipper must initial the option selected.

_____ I did not request a written estimate on this shipment and understand that I will be required to pay charges shown on this contract.

______ I understand this shipment is moving under a binding estimate (guaranteed or not-to-exceed) and that I will be required to pay in accordance with that estimate.

______ I understand this shipment is moving under a nonbinding estimate and I will be required to pay charges shown on this contract.

See attached **"Estimated Cost of Services."**

VALUATION: Shipper must initial the option selected.

______ Basic Value Protection. I release this shipment to a value of 60 cents per pound per article. This lower level of protection is provided at no additional cost beyond the base rate. However, it provides only minimal protection that is considerably less than the average value of household goods.

______ Full Value Protection. I release this shipment to a value of $4.00 times actual weight in pounds of shipment or declared lump sum value of $____________ (Declared value must be at least $4.00 per pound times weight of shipment.)

See attached "Addendum to Uniform Household Goods Bill of Lading."

EXTRAORDINARY VALUE ARTICLE DECLARATION

I acknowledge that I have prepared and retained a copy of "Inventory of Items Valued in Excess of $100 Per Pound Per Article" and that I have given a copy of this inventory to the carrier's representative. I also acknowledge that the carrier's liability for loss of or damage to any article valued in excess of $100 per pound per article will be limited to $100 per pound for each pound of the damaged article (based on actual article weight) not to exceed the declared value of the entire shipment, unless I have specifically identified such articles on the inventory and for which a claim for loss or damage is made.

SIGNED: ____

To be signed when shipment is received by carrier

All property was received in good condition, except as noted on the inventory form.

Driver's signature: __________________ Date: _________

I have read this contract and its attachments thoroughly and release my property to the carrier subject to the terms and conditions thereof.

Shipper's signature: ________________ Date: _________

To be signed at time of delivery

All property was received in good condition, except as noted on the inventory form.

Shipper's signature: ________________ Date: __________

QUESTIONS ABOUT THIS FORM OR YOUR MOVE?
Call the NCUC-Public Staff's Transportation Division
at 919-733-7766

CONSIGNEE
STREET ADDRESS
CITY & STATE

NOTIFY IN CASE OF DELAY ______________ **CHARGES** ________________
NAME
ADDRESS

BILL TO:
ADDRESS
CITY & STATE
ATTN: **PO. NO.**

FOR ALL MOVES LESS THAN 35 MILES

HOURLY					
H	Time Move Started				
O	Time Move Finished				
U	Travel Time (1 hour per 50 miles)				
R		**Men**	**Hours**	**Rate**	**Charges**
L	Regular Hours				
Y	Overtime Hours				
	Depreciated Value Protection				
	Full Value Protection				
			Total Hourly Charges		

PACKING	Description		Quantity	Rate	Charges
	Dishpack or Barrel				
P	Cartons	1.5			
		3.0			
A		4.5			
		6.0			
C		6.5			
	Wardrobes				
K	Crib Mattress				
	Twin Mattress				
I	Double Mattress				
	King/Queen Mattress				
N	King Single Mattress				
	Corrugated Cont.(Mirror & Picture)				
G	Crates, minimum				
	Crates _________ cu ft				
	Grandfather Clock Carton				

	ORIGINAL	REWEIGH
LBS. GROSS	__________	__________
LBS. TARE	__________	__________
LBS. NET	__________	__________
BREAK POINT WT.	__________	__________

Total Packing Charges

Tariff	Sec	Miles	Weight	Rate	Linehaul Charges
MRT	3				

Description		Rate	Charges
Extra Pickup or Delivery:			
At:			
Excessive Distance Carry at Origin:	ft.		
Excessive Distance Carry at Destination:	ft.		
Flight Carry at Origin:			
Flight Carry at Destination:			
Appliance Service			
Appliance Unservice			
Piano Handling			
Additional Labor:			
Bulky Articles:			
Packing Material Purchased by Shipper			
Advanced Charges:			
Third Party Charges			
Depreciated Value Protection			
Full Value Protection			

Storage-In-Transit		Rate	Charges
Transportation To or From Whse:	lbs.		
Warehouse Handling			
Storage From: To:	No. Mos.		
Extended Valuation (10% of Storage Charge)			

Payment Acknowledgment		Total Charges
On nonbinding estimates, 110% rule applies. See "**Estimated Cost of Services**"	**Total**	
Prepayment Received By	**Prepayment**	
Payment Received at Destination By	**Balance Due**	

ADDENDUM TO UNIFORM HOUSEHOLD GOODS BILL OF LADING

SHIPPER DECLARATION OF VALUE

IMPORTANT: There are two (2) options available to cover loss and/or damages:

OPTION 1: **Basic Value Protection.** This lower level of value protection is provided at no additional cost. However, it only provides minimal protection that is considerably less than the average value of household goods. The carrier's maximum liability shall be $.60 per pound for the actual weight on any lost or damaged article or articles, if the shipment has been expressly released by the shipper to such value per article. Under this option, a claim for any article that may be lost, destroyed or damaged while in the custody of your mover will be settled based on the weight of the individual article multiplied by 60 cents. For example, damages to an item weighing 400 pounds would result in a maximum claim settlement of $240. Basic Value Protection provides minimal protection, and it is possible that settlement of any claim under this level of valuation will not be satisfactory to you.

OPTION 2: **Full Value Protection.** The minimum value of the shipment will be $4.00 times the weight of the shipment. However, you have the right to declare that your shipment has a greater value and pay for that increased protection. If items are lost, the mover will have the options of replacing them with articles of like kind and quality or paying the replacement costs as determined by current market value. If items are damaged, the mover will have the same options, plus the additional options of repairing the items or paying the repair cost. All damaged items that are either replaced or reimbursed at full-market value become the property of the mover. Under this option, for example, if the total weight of your shipment is 8,000 pounds, then the total value of your entire shipment is established to be $32,000 and the charge for that level of protection would be $240. If you determine that your shipment has a value greater than the $50,000 minimum amount of insurance coverage that the Commission requires movers to have, you may want to request written verification of additional coverage from your mover to ensure your shipment will be adequately covered.

** DECLARATION **

Prior to the move, the shipper must select one of the options listed below. If the carrier fails to require the shipper to choose one of the liability options, the shipper will be considered to have chosen Option 1 (Basic Value Protection).

Shipper hereby releases the entire shipment to a value not exceeding:

____Option 1 – Basic Value Protection -$.60 per pound per article.
Signature of Shipper and Date

____Option 2 - Full Value Protection - $4.00 times the actual
Signature of Shipper and Date weight in pounds of shipment or a declared lump sum value of $ ____________.

This document shall be completed and signed **PRIOR TO MOVE** and made a permanent part of the Bill of Lading.

BILL OF LADING/ORDER NO: _______________________ DATE ___________________________

NAME OF SHIPPER ____

( ) HOURLY RATED MOVE ( ) WEIGHT & DISTANCE MOVE

CARRIER REPRESENTATIVE ____
SIGNATURE

ESTIMATED COST OF SERVICES

CARRIER'S NAME
CARRIER'S ADDRESS
CARRIER'S CITY & STATE
CARRIER'S TELEPHONE
CARRIER'S C #

[QUESTIONS ABOUT THIS FORM OR YOUR MOVE? Call the NCUC-Public Staff's Transportation Division at 919-733-7766]

ORIGIN

Shipper ___________________________Phone_____________

Loading Address ______________________________________

City ________________________________ , NC ___________

Preferred Loading Date _________________________________

DESTINATION

Consignee _________________________Phone____________

Delivery address ____________________________________

City __________________________________, NC __________

Preferred Delivery Date ________________________________

IMPORTANT NOTICES

A. This proposal is for listed items and services only. Additional items and services may result in additional costs.
B. Carrier and shipper agree that any additional items or services not included in this proposal may be set forth in an addendum executed by the carrier and shipper.
C. Shipper must choose a level of carrier liability (valuation protection) for the shipment. Options are basic value protection ($.60 per pound per article) and full value protection. See the BROCHURE issued by the NC Utilities Commission explaining these options. If shipper does not choose an option, the shipment defaults to basic value protection at no additional cost to the shipper.
D. Shipper shall be required to pay for all charges prior to unloading, in cash or by certified check or money order, except as may be otherwise agreed in writing between carrier and shipper.
E. Nonbinding estimates are subject to "110% Rule" (MRT Rule 13). The carrier must, upon request of the shipper, relinquish possession of the shipment upon payment of not more than 110% of the estimated charges and shall defer demand for the payment of the balance of any remaining charges for a period of thirty (30) days following the date of delivery.

TYPE OF ESTIMATE (See Important Notices Above)

_______ Proposed charges set forth below are NONBINDING for the items listed. Actual charge shall be determined after all services have been completed.
_______ Proposed charges set forth below are BINDING AND GUARANTEED for the items listed for ______ days.
_______ Proposed charges set forth below are BINDING AND NOT-TO-EXCEED for the items listed for _____ days. Actual charges shall be determined after all services have been completed but shall not exceed the amount shown below under "Total Binding and Not-To-Exceed Charges".

PROPOSED COST OF SERVICES | **TRANSPORTATION COST** | **PROPOSED CHARGES**

1. Weight and distance (MRT, Sec. 3) Miles ________ Est. Weight ________ lbs. Moving at ______ per cwt. Charge __________________
2. Hourly rated (MRT, Sec. 2) Vans _______ Men _______ Est. Hours _______ Rate per Hour _________ Charge __________________

PROPOSED COST OF SERVICES | **STORAGE-IN-TRANSIT** | **PROPOSED CHARGES**

3. A) Storage: Weight ___________lbs. Rate per Month __________ Number of Months _______ Charge __________________
B) Extended Valuation: 10% of Storage Charge (does not apply to Basic Value Protection) Charge __________________
C) Warehouse Handling: Weight ___________ lbs. Rate per cwt. ___________Charge __________________
D) Storage Pick-Up or Delivery Charge: Weight ___________ lbs. Rate per cwt. ____________Charge __________________

PROPOSED COST OF SERVICES | **PACKING CHARGES** | **PROPOSED CHARGES**

DESCRIPTION	CU FT	QUANTITY	RATE	CHARGE
Dishpack or Barrel	5.0			
Cartons	1.5			
Cartons	3.0			
Cartons	4.5			
Cartons	6.0			
Cartons	6.5			
Wardrobe Carton	10			
Crib Mattress				
Twin Mattress				
Double Mattress				
King/Queen Mattress				
King Single Mattress				
Corrugated Container (Mirror & Picture)				
Crates, Minimum				
Crates __________ cu. ft.				
Grandfather Clock Carton				

4. Packing & Unpacking Charge Charge __________________

PROPOSED COST OF SERVICES	OTHER CHARGES	PROPOSED CHARGES
5. Extra stop(s) ____		_________________
6. Excessive Distance Carry: Ft. _______ Weight ______________ Rate per cwt. __________		_________________
7. Flight Carry: No. Flights ________ Weight ______________ Rate per cwt. __________		_________________
8. Appliance Service _________________ Appliance Unservice ____________________		_________________
9. Bulky Articles ____		_________________
10. Other Charges ____		_________________
	SUBTOTAL	_________________
11. Third Party Charges ____		_________________

PROPOSED COST OF SERVICES	VALUATION	PROPOSED CHARGES
12. Basic Value Protection –	Maximum liability will be at $.60/lb/article regardless of the actual value of lost or damaged items.	NO CHARGE
13. Full Value Protection	Weight ___________lbs @ $4.00/lb $____________ x $.75/$100 =	_________________

ESTIMATED COSTS

TOTAL NONBINDING CHARGES _________________
TOTAL BINDING AND GUARANTEED CHARGE _________________
TOTAL BINDING AND NOT-TO-EXCEED CHARGES _________________

Estimator _______________________________ Date ___________ Shipper ________________________________ Date __________________

UNIFORM HOUSEHOLD GOODS BILL OF LADING - 35 MILES OR LESS

CARRIER'S NAME & ADDRESS
CARRIER'S TELEPHONE
CARRIER'S C#

CARRIER REFERENCE NO.

[QUESTIONS ABOUT THIS FORM OR YOUR MOVE? Call the NCUC-Public Staff's Transportation Division at 919-733-7766]

FROM	**SHIPPER:**	**BINDING PRICE (GUARANTEED OR NOT-TO-EXCEED)** $	
	COMPANY:		
	STREET ADDRESS:	DATE	TIME LEFT WAREHOUSE
	CITY & STATE		
	TELEPHONE:	VAN#	TIME ARRIVED JOB
TO	**CONSIGNEE**		
	STREET ADDRESS:	DRIVER	TIME DEPART JOB
	CITY & STATE:		
AGREED LOAD DATE:		HELPER	TIME RETURNED WAREHOUSE
PREFERRED DELIVERY DATE:			
NOTES:		HELPER	TOTAL HOURS
		HELPER	
		HELPER	OTHER

REQUIRED SIGNATURES

I HAVE RECEIVED THE NCUC BROCHURE EXPLAINING MY RIGHTS.
SHIPPER'S SIGNATURE: ________________________

NOTE: SHIPPER MUST INDICATE CHOICES MADE ON BOTH ITEMS LISTED BELOW BY INITIALING ON THE APPROPRIATE LINE (Estimates & Valuation)

ESTIMATES: Shipper must initial the one option selected.

_____ I did not request a written estimate on this shipment and understand that I will be required to pay charges shown on this contract.

______ I understand this shipment is moving under a binding estimate (guaranteed or not-to-exceed) and that I will be required to pay in accordance with that estimate.

______ I understand this shipment is moving under a nonbinding estimate and I will be required to pay charges shown on this contract.

See attached **"Estimated Cost of Services."**

VALUATION: Shipper must initial the one option selected.

______ **Basic Value Protection**. I release this shipment to value of 60 cents per pound per article. This lower level of protection is provided at no additional cost beyond the base rate. However, it provides only minimal protection that is considerably less than the average value of household goods.

______ **Full Value Protection**. I release this shipment to a value of $4.00 times actual weight in pounds of shipment or declared lump sum $___________ (Declared value must be at least $4.00 per pound times weight of shipment.)

See attached **"Addendum to Uniform Household Goods Bill of Lading."**

EXTRAORDINARY VALUE ARTICLE DECLARATION

I acknowledge that I have prepared and retained a copy of "Inventory of Items Valued in Excess of $100 Per Pound Per Article" and that I have given a copy of this inventory to the carrier's representative. I also acknowledge that the carrier's liability for loss of or damage to any article valued in excess of $100 per pound per article will be limited to $100 per pound for each pound of the damaged article (based on actual article weight) not to exceed the declared value of the entire shipment, unless I have specifically identified such articles on the inventory and for which a claim for loss or damage is made.

SIGNED: ____________________________________

To be signed when shipment is received by carrier

All property was received in good condition, except as noted on inventory form.

Driver's signature: ______________________________ Date: _____________

I have read this contract and its attachments thoroughly and release my property to the carrier subject to the terms and conditions thereof.

Shipper's signature: ______________________________ Date: _____________

To be signed at time of delivery

All property was received in good condition, except as noted on the inventory form.

Shipper's signature: ______________________________ Date: _____________

HOURS	RATE		
TRAVEL TIME 1 HR PER 50 MILES	RATE		
Total Hourly Charges			

Description	Qty	Rate	Charges
Dishpack or Barrel			
1.5 cu. ft. (Small) Cartons			
3.0 cu. ft. (Medium) Cartons			
4.5 cu. ft. (Large) Cartons			
6.0 cu. ft. (Ex-Large) Cartons			
Wardrobes			
Crib: Twin: Dbl: King/Qn: King Sgl:			
$			
Total Packing Charges			

Description		Rate	Charges
Appliance Service			
Appliance Unservice			
Piano Handling			
Packing Material Purchased			
Bulky Articles			
Third Party Charges:			
Depreciated Value Protection			
Full Value Protection			
Storage-In-Transit		Rate	Charges
Transportation To/From Whse:	lbs.		
Warehouse Handling			
Storage From: To:	No. Mos.		
Extended Valuation (10% of Storage Charge)			
Payment Acknowledgment			Total Charges
On nonbinding estimates, 110% rule applies. See "**Estimated Cost of Services**"		**Total**	
Prepayment Received By		**Prepayment**	
Payment Rec'd at Destination By		**Balance Due**	

ESTIMATED COST OF SERVICES - 35 MILES OR LESS

Carrier's Name
Address, City & State
Phone & C#

QUESTIONS ABOUT THIS FORM OR YOUR MOVE? Call the NCUC-Public Staff's Transportation Division at 919-733-7766

ORIGIN **DESTINATION**

Shipper______________________________ **Phone** ______________ **Shipper** _______________________________ **Phone** _____________

Loading Address ____ **Delivery Address** ____

City __________________________________, **NC** ______________ **City** ___________________________________, **NC** _______________

Preferred Loading Date _____________________________________ **Preferred Delivery Date**______________________________________

IMPORTANT NOTICES

A. **This proposal is for listed items and services only. Additional items and services may result in additional costs.**

B. **Carrier and shipper agree that any additional items or services not included in this proposal may be set forth in an addendum executed by the carrier and shipper.**

C. **Shipper must choose a level of carrier liability (valuation protection) for the shipment. Options are $.60 per pound per article and full value protection. See the BROCHURE issued by the NC Utilities Commission explaining these options. If shipper does not choose an option, the shipment defaults to basic value protection, which requires no additional payment from the shipper.**

D. **Shipper shall be required to pay for all charges prior to unloading, in cash or by certified check or money order, except as may be otherwise agreed in writing between carrier and shipper.**

E. **Nonbinding estimates are subject to "110% Rule" (MRT Rule 13). The carrier must, upon request of the shipper, relinquish possession of the shipment upon payment of not more than 110% of the estimated charges and shall defer demand for the payment of the balance of any remaining charges for a period of thirty (30) days following the date of delivery.**

TYPE OF ESTIMATE (See Important Notices Above)

_______ **Proposed charges set forth below are NONBINDING for the items listed. Actual charge shall be determined after all services have been completed.**

_______ **Proposed charges set forth below are BINDING AND GUARANTEED for the items listed for ______ days.**

_______ **Proposed charges set forth below are BINDING AND NOT-TO-EXCEED for the items listed for ______ days. Actual charges shall be determined after all services have been completed but shall not exceed the amount shown below under "Total Binding and Not-To-Exceed Charges".**

HOURLY CHARGES

Hourly rated (MRT, Sec 2) Vans _____, Men _____, # Hours ______ at Rate / Hour _________ Total Estimated Hourly Charges_______________

Travel Time – 1 Hour for each 50 miles or fraction thereof: _________ (No. of Hours)

PACKING & ACCESSORIAL CHARGES

Description	Qty	Rate	Charges	Description	Qty	Rate	Charges
Dishpack or Barrel				Appliance Service			
1.5 cu. Ft. (Small) Cartons				Appliance Unservice			
3.0 cu. Ft. (Medium) Cartons				Piano Handling			
4.5 cu. Ft. (Large) Cartons				Packing Material Purchased			
6.0 cu. Ft. (Ex-Large) Cartons							
				Bulky Articles			
Wardrobes							
Crib: Twin: Dbl:				Third Party Charges:			
Queen/King: King Sgl:				**Storage-In-Transit: lbs**		Rate	Charges
Mirror/Picture Pac				Transportation To/From Whse:			
Crates, minimum				Warehouse Handling			
Crates __________ cu ft				Storage Per Month			
Grandfather Clock Carton				Extended Valuation 10% of Storage Charge (does not apply to Basic Value Protection)			
				TOTAL PACKING, ACCESSORIAL & SIT			

VALUATION (Carrier's Maximum Liability)

BASIC VALUE PROTECTION - $.60 / lb/ article – Maximum liability will be at $.60/lb/article regardless of the actual value of lost or damaged items.

FULL VALUE PROTECTION Constructive Wt_______ lbs @ $4.00 / lb or Declared Value $_____________ X $.75/$100 = _______________

(Constructive Weight = 7 lbs. per cubic foot of properly loaded van space)

ESTIMATED CHARGES **HOURLY PKG/ACC/SIT VALUATION = TOTAL**

TOTAL NONBINDING CHARGES __________________ + _______________+ _______________= _________________

TOTAL BINDING & GUARANTEED CHARGES __________________+_______________+_______________= ____________

TOTAL BINDING & NOT-TO-EXCEED CHARGES__________________+_______________+_______________= ____________

CUSTOMER SIGNATURE: ______________________________ESTIMATOR: __________________________ DATE _________

MOVING 101

A NORTH CAROLINA CONSUMER'S GUIDE

Issued by the North Carolina Utilities Commission

www.ncuc.net

Effective: January 1, 2015

TABLE OF CONTENTS

I. INTRODUCTION

If you pay someone to perform a move in North Carolina, whether the move is across town or across the state, the move is probably regulated by the North Carolina Utilities Commission (Commission). Intrastate household goods movers operating in North Carolina must have a certificate ("C" number) issued by the Commission. Such certificated movers are required to have insurance, to meet other consumer protection requirements, and to comply with the provisions of the Maximum Rate Tariff (MRT). [Note: Interstate and international shipments, government and military moves, commercial moves (offices and equipment), and new furniture/retail deliveries are not under the Commission's jurisdiction.]

The Commission issued the MRT to establish the maximum rates movers may charge their customers for the services they render. The tariff also provides the forms which must be used and the information which must be given to each customer, as well as the rules and regulations governing these moves. The MRT is available on the Commission's website at http://www.ncuc.net/appforms/trans/maxrate.pdf. If you have difficulty accessing the MRT online, you may contact the Commission (919-733-4036) or Public Staff (919-733-7766) to discuss the MRT provisions.

BE SMART! HIRE A COMMISSION-CERTIFICATED MOVER. Minimize the risk of moving-day delays, damages, inflated charges, or loss of your possessions by hiring a legal (certificated) mover. A list of legal movers in North Carolina is available on the Commission's website at http://www.ncuc.net/consumer/carriers.pdf. The list is updated monthly. Subsequently cancelled or suspended certificates, as well as newly-issued certificates, will not be reflected in the list until the next update. If you have difficulty accessing the list online or want to check a mover's current status, you may contact the Commission (919-733-4036) or the Public Staff (919-733-7766).

The Commission requires movers to carry a minimum amount of $50,000 for general liability insurance and a minimum amount of $50,000 for cargo insurance. If you believe that your shipment has a value greater than the $50,000 minimum amount of insurance coverage required by the Commission, you may want to request written verification of additional coverage from your mover to ensure your shipment will be adequately covered.

The Maximum Rate Tariff establishes "maximum" rates a mover can charge; however, you and the mover are allowed to negotiate moving rates that are lower than the established maximum rates.

Sometimes customers encounter movers who do not have a certificate from the Commission. Such uncertificated movers may not realize that intrastate household goods moving is a regulated activity. Please let us know if you encounter someone offering intrastate household goods moving services who is not on the Commission's list: 919-733-7766.

II. HOW MOVERS CHARGE FOR MOVES WITHIN NC

MOVES OF 35 MILES OR LESS (HOURLY RATES): Moves of 35 miles or less are billed at hourly rates based upon the number of workers/vans and the time it takes to perform the move. The regulations define the maximum rates that movers may charge which allows movers and their customers to negotiate the rates to be used. The "clock" starts when the mover arrives at your home, and it stops when all the services at the destination have been completed. A charge may be assessed for traveling to your current home and from your new home. Time will be rounded up to the nearest quarter hour.

MOVES OF 36 MILES OR MORE (WEIGHT/DISTANCE RATES): Moves greater than 35 miles are billed based on the weight of the shipment and the distance between origin and destination. That distance is calculated using the current, official map issued by the NC Department of Transportation or, in some instances, special Commission-approved mileage software. Any other online mapping services or odometer readings may not be used by movers for determining distance, although they may be used for directions.

The regulations define the maximum rates that movers may charge which allows movers and their customers to negotiate the rates to be used up to the maximum. The mover will weigh the vehicle prior to loading your household goods (tare weight) with a full gas tank and all the supplies to be used for your move. After the vehicle has been loaded, the mover will weigh the truck again (gross weight). The weight of the shipment (net weight) is determined by subtracting the tare weight from the gross weight. All weights will be shown on the Bill of Lading. However, if no adequate scale is available, a “constructive weight” (7 pounds per cubic foot of properly loaded van space) may be used to determine the weight of your shipment.

If it seems necessary, you may request that your shipment be reweighed prior to delivery. Reweighing will be done only where it is practical to do so. An additional charge may be assessed for reweighing if the difference between the two net weights is less than 100 pounds on a shipment weighing less than 5,000 pounds or is less than 2% of the lower net weight on a shipment weighing more than 5,000 pounds. The lower of the two net weights will be used in determining your charges.

EXTRA SERVICES: Movers typically perform services other than simply transporting your possessions. The following are examples of services which may add to the cost of the move:

Packing/unpacking;

Disconnecting/reconnecting appliances (washer, dryer, icemaker, etc.);

Loading or unloading bulky articles (motorcycles, sheds, cars, hot tubs, pianos, pool tables, freezers, etc.);

Shuttle services between the truck and the residence, when needed;

Carrying items long distances;

Using stairs or elevators in some circumstances;

Going into hard to reach spaces (attics, basements, etc.); and

Transporting boats and their trailers.

All charges may apply to weight/distance moves; some may apply to hourly moves. Movers may also hire a third party to perform certain services, and those charges will be added to the cost of the move. REMEMBER TO BE ON TIME OR YOU MAY PAY ADDITIONAL CHARGES.

EXPEDITED DELIVERY SERVICE: Most customers expect delivery within the next day or so after their goods are loaded. However, sometimes movers cannot deliver that quickly, particularly on smaller loads. If you request it, delivery can occur on or before a specific day. This earlier-than-normal delivery is called “expedited service” and is subject to the availability of the trucks. The rates that apply will be higher than you would normally pay and are based upon the number of miles involved in your move and the weight of your goods. If you agree to pay the extra charges for expedited service, you must sign at a certain section on the Bill of Lading acknowledging that you understand the shipment is moving under the provisions of expedited service which is more expensive than standard delivery service.

III. HOW MOVERS GIVE COST ESTIMATES OR QUOTES

PHONE QUOTES: When you call a mover, he may give you a quote over the phone. Movers vary in their ability to provide good phone quotes. Some are better at it than others. As with any type of quote, the more accurate the information you provide to the mover the more accurate quote you are likely to get.

INTERNET QUOTES: BE CAREFUL! The Internet is a valuable tool for investigating movers and comparing average moving costs. However, you should not commit to using a mover found this way without acquiring a lot more information. For example, you need to know where the mover is physically located, in case you later discover loss or damage and are unsuccessful in reaching the mover by telephone. Also, the website may actually be for a moving services broker, who arranges for a moving company to perform the move. As a result, somebody you have never heard of or researched, such as an uncertificated mover, may show up in a rental truck with a crew having a questionable reputation and an unprofessional attitude.

Additionally, you may want to include MovingScam.com in your research of moving companies. That website (www.movingscam.com) specializes in warning customers about moving companies. To verify that a mover is properly certificated to perform intrastate moves in NC, you can check the Commission website at http://www.ncuc.net/consumer/carriers.pdf or call its offices (919-733-4036) or those of the Public Staff (919-733-7766). PLEASE PROCEED CAUTIOUSLY WHEN BOOKING A MOVE OVER THE INTERNET.

GETTING A WRITTEN ESTIMATE: If you request it, a mover is required to give you a free written estimate on a Commission-approved form. Most movers will not provide a written estimate unless they see the items to be moved. Make sure you understand how the estimate is calculated. It is a good idea to get written estimates from several moving companies and compare them to make your selection. Be sure to give all of them the same information. After the estimate is provided, you might want to ask for suggestions on how you could reduce the costs. The estimator can usually offer some helpful hints. A mover is not required to provide a written estimate if you request the estimate less than five business days prior to the move or if the total weight of the move is less than 500 pounds.

ADDENDUM TO A WRITTEN ESTIMATE: Sometimes circumstances change after a written estimate has been given. For example, you agree to sell all the furniture in your second bedroom to a neighbor rather than move it, or the friend who planned to buy your hot tub changed his mind and you now need to move it. If these types of changes occur when you have a written estimate, an Addendum to the Estimated Cost of Services (Addendum) form needs to be completed to retain the integrity of the written estimate. If you request services not covered by the written estimate and you do not sign the Addendum, the carrier may refuse to perform the requested services.

IV. THREE TYPES OF WRITTEN ESTIMATES

Non-Binding: A nonbinding written estimate shows the approximate charges for the services to be provided. At the time of delivery, the mover will expect payment for the actual charges. If the actual charges are greater than 110% of the charges shown on the written estimate plus any addendum to that written estimate, you may request to pay 110% of the charges at the time of delivery and the balance within 30 days. Payments received after 30 days may be subject to a finance charge of 1% per month. Of course, you can pay for the move in full at the time of delivery.

Binding Guaranteed: A binding guaranteed written estimate is fully binding on both you and the mover. If any additional services are performed by the mover at your request, which are not covered in the written estimate, additional charges may apply and you will be expected to sign an Addendum to the written estimate acknowledging such changes. At the time of delivery, the mover will expect payment of the written estimate, plus any charges for additional services. If services covered in the written estimate are no longer required, a properly completed Addendum will acknowledge the removal of the charges for those services from the written estimate.

Binding Not-to-Exceed: A binding not-to-exceed written estimate is a guaranteed maximum charge for the move as long as you do not request additional services. After the move has been completed, all charges will be calculated. At the time of delivery, if the actual charges are less than the written estimate, you will pay the actual charges; if the actual charges are greater than the written estimate, you will pay the written estimate. However, if any additional services are performed by the mover at your request, which are not covered in the written estimate, additional charges may apply and you will be expected to sign an Addendum to the written estimate acknowledging such changes.

V. HOW TO PAY FOR THE MOVE

PAYMENT IS EXPECTED AT TIME OF DELIVERY: Most movers only accept cash, certified check, money order, or travelers check for payment at the time of delivery; they might not accept a personal check. Many movers do not have the ability to process credit or debit cards. Prior to your move, make sure you understand the form of payment which will be acceptable to your mover.

VI. STORAGE OPTIONS

STORAGE-IN-TRANSIT (180 days or less): Short-term storage for a period not to exceed 180 days is called "storage-in-transit" (SIT) and, if requested, it may be performed for an additional charge. However, not all movers offer this service. For SIT, the rates, rules, and regulations of the Commission apply. SIT rates are based upon the weight of the shipment and not by the number of containers. Usually, the mover will require payment of the charges already incurred plus the first month's storage at the time of delivery into storage. Charges are calculated on 30-day increments and may be prorated. Sometimes customers cannot take delivery of their possessions within a 180-day period. If that happens, the shipment changes from "storage-in-transit" to "permanent storage." ***BE SURE YOU KNOW THE LOCATION OF THE WAREHOUSE WHERE YOUR GOODS ARE STORED. ALSO, YOU MAY WANT TO REQUEST WRITTEN VERIFICATION THAT THE MOVER HAS ADEQUATE INSURANCE COVERAGE WHILE YOUR SHIPMENT IS IN STORAGE.***

PERMANENT STORAGE (More than 180 days): Permanent storage is storage for more than 180 days, and the storage charges are not under the Commission's jurisdiction. Sometimes the customer knows in advance that storage is needed for longer than 180 days and will contract for permanent storage. Under such circumstances, the shipment is considered "delivered" when it arrives at the storage facility which is its destination. The transport of such shipment in and out of permanent storage is conducted under separate moving contracts subject to the rates, rules, and regulations of the Commission if the move is intrastate. BE SURE YOU KNOW THE LOCATION OF THE WAREHOUSE OR THE WAREHOUSE OF THE MOVER'S AGENT WHERE YOUR GOODS ARE STORED.

CUSTOMER-CONTROLLED STORAGE: Sometimes customers want their possessions to be delivered to a public storage facility (also called, "mini-storage") which will be under the customer's control. If you need such storage, please understand that the mover's liability ends once the items are in the storage unit. Therefore, you should be present at the time of delivery to check for damage to your items BEFORE they are deposited into the unit. Damages discovered after the moving crew leaves can be denied. You should also be present at the delivery to provide substitute padding or other protection for your furniture, unboxed items, etc. while they are in storage. The mover transported your items using the mover's pads; the crew will remove and take those pads with them when they leave. Of course, the rates you pay for this type of storage are not under the Commission's jurisdiction.

VII. *TWO* TYPES OF VALUATION

Customers will often ask movers, "What kind of insurance do you have in case something is lost or damaged?" ***While the Commission requires movers to carry a minimum of $50,000 for general liability insurance and a minimum of $50,000 for cargo insurance,*** the settlement of your claim is defined by the valuation you select. Valuation establishes the total value of your shipment in case of catastrophic loss and also governs how the mover will resolve your claim for loss of or damage to individual items. The type of valuation will cover the entire shipment; you cannot select one type for part of the shipment and another one for select pieces. ***Therefore, if the amount of protection you desire exceeds the $50,000 minimum amount required by the Commission, you may want to request written verification of additional coverage from your mover to ensure that your shipment will be adequately covered.*** You must explicitly indicate your choice in two places: on the Bill of Lading and on the Addendum to the Bill of Lading (making sure that they both show the same choice). ***If the shipper fails to select one of the liability options available, the shipment will be considered released at a value of $.60 per pound per article (basic value protection).***

As discussed below, there are ***two*** types of valuation available for both weight/distance and hourly-rated moves. However, hourly-rated shipments are not weighed. Therefore, if you decide to purchase depreciated or full value protection for an hourly-rated move, the mover will estimate the weight of your shipment to calculate its value.

REMEMBER: You must select your level of valuation before the move begins. Once it starts, the selection cannot be changed. Also, be sure to provide the mover with a list of items you believe to be of extraordinary value (see Articles of Extraordinary Value). While preparing that list, customers sometimes realize that they have undervalued their shipment by simply accepting the minimum required. If everything on the truck is destroyed, are you prepared to accept a check for the value of the shipment shown on the estimate? If not, talk to someone about declaring an increased amount (and paying a higher fee).

<u>**Basic Value Protection - No Charge:**</u> ***This lower level of value protection is provided at no additional cost. However, it only provides minimal protection that is considerably less than the average value of household goods.*** The mover's maximum liability will be 60¢ per pound based upon the weight of any lost or damaged items, regardless of its actual value. For example, damage to your refrigerator weighing 400 pounds would result in a maximum claim settlement of $240. Basic Value Protection provides minimal protection, and it is possible that settlement of any claim under this level of valuation will not be satisfactory to you. Under this type of valuation, for example, if the total weight of your shipment is 8,000 pounds, then the total value of your entire shipment is established to be $4,800.

<u>**Full Value Protection - 75¢ per $100 of Value:**</u> The minimum value of the shipment will be $4.00 times the weight of the shipment. However, you have the right to declare that your shipment has a greater value and pay for that increased protection. If items are lost, the mover will have the options of replacing them with articles of like kind and quality or paying the replacement cost as determined by current market value. If items are damaged, the mover will have the same options, plus the additional options of repairing the items or paying the repair cost. All damaged items that are either replaced or reimbursed at full-market value become the property of the mover. Under this type of valuation, for example, if the total weight of your shipment is 8,000 pounds, then the total value of your entire shipment is established to be $32,000 and the charge for that level of protection would be $240. However, if you decided that your shipment has a greater value, maybe $45,000 rather than the calculated minimum of $32,000, you could establish that your shipment value is $45,000 and the charge for that level of protection would be $337.50.

VIII. ARTICLES OF EXTRAORDINARY VALUE

Items of extraordinary value are defined as those having a value greater than $100 per pound. Such items, e.g., crystal, fur garments, antiques, etc., should be specifically listed in writing for the mover and signed for on the Bill of Lading. If not listed, the mover's liability could be limited to $100 per pound per article (based upon the actual article weight) regardless of the valuation you selected. For example, a claim for a broken $500 collectible weighing one pound could be covered for only $100. However, if such collectible item is claimed on the inventory list as an item of extraordinary value at $500, the mover's liability may be up to $500 if you selected Full Value Protection. But remember, even if you declare items of extraordinary value, the total value of your entire shipment is still no more than the total value that is established under the type and total amount of valuation protection you select. Keep a copy for your records of the inventory list you provide to your mover. It is highly recommended that you transport certain valuable items yourself, such as jewelry, stamp and coin collections, cash, guns, legal and medical documents, tax records, genealogy research, and other such irreplaceable items.

IX. PARTICLE BOARD FURNITURE

North Carolina is one of only four states in the nation that acknowledges the unique characteristics of ready-to-assemble furniture made from press board, particle board, or other similar engineered materials. These items are shipped unassembled from the manufacturer for assembly by the customer or the retail store. Most of this furniture is not designed with the extra structural pieces to adequately brace the unit for movement out of or into a residence and may not withstand the normal truck vibration. Assembly instructions frequently suggest that the connecting pieces (often using dowels) be glued in place. While the gluing does not significantly improve the structural integrity of the piece, it makes disassembly impossible without creating substantial, irreparable damage. You need to be aware that the mover's maximum liability on such furniture is 60¢ per pound per article or $50 per article, whichever is greater, regardless of the type of valuation you select.

X. PACKING DAY

You should accompany the crew leader on a visual inspection of your home and provide any special instructions. Point out items not to be packed, items valued over $100 per pound (see Articles of Extraordinary Value), fragile items, items that need to arrive first, and items that need servicing (such as washers and dryers).

You may choose to pack some or all boxes yourself. However, movers are not liable for any damages to items you pack unless there is external damage to the box and an inspection is done at delivery. If a box you pack is lost and listed on an inventory sheet, the mover may be liable. You will be charged for packing materials used or provided by the mover.

Once packing is completed, you and the crew leader should conduct another visual inspection of your home to make sure all required items have been packed. Check closets, attics, basements, cabinets, detached buildings, and other areas of the property to ensure that nothing has been missed. Make sure all boxes are properly marked with room placement and general contents to help inform the crew where the boxes should be delivered within your new residence.

XI. LOADING DAY

Either you or your representative should be present at the time of loading and unloading. The mover might perform a detailed inventory of some or all items. If so, review the inventory sheets to make sure you agree with the mover's assessment of the condition of your items.

Once loading has been completed, you and the driver should walk through the house to make sure all items are on the truck. Check closets, attics, basements, cabinets, detached buildings, and other areas of the property to ensure that nothing has been missed.

You are responsible for preparing your appliances for shipment. Alternatively, your appliances may be serviced (disconnected and prepared for shipment) by a third-party company or the moving company for a further charge. Furniture pads, covers, and other standard protective materials which are part of the mover's regular equipment are included in the transportation rates.

MAKE SURE YOUR MOVER HAS YOUR CORRECT DESTINATION ADDRESS, DETAILED DIRECTIONS TO FIND YOUR NEW RESIDENCE, AND CONTACT INFORMATION INCLUDING COMPLETE NAMES AND PHONE NUMBERS.

XII. DELIVERY DAY

You should walk through the new residence with the driver to determine the best way to unload and place your possessions. The crew will assemble all items that they disassembled at origin. They will not assemble items disassembled by others. Appliances will be serviced by the same party that serviced them at origin. Remember, servicing appliances may result in additional charges.

You may request that boxes packed by the mover be unpacked at delivery at no additional charge. If you want the crew to unpack, be sure to let the mover know before moving day, so the scheduler can allow enough time for that service. The crew does not put items in cabinets, drawers, etc., although they will hang clothes in closets. The packing materials will be removed from the premises on the delivery day. If the crew has to return another day to unpack and/or remove the packing materials, an additional charge may apply.

After the delivery is completed, you should walk through the rooms with the driver to conduct a final inspection. IF YOU DISCOVER DAMAGES, DO NOT DISPOSE OF ANY DAMAGED ITEMS OR THE PACKING MATERIALS USED FOR THOSE ITEMS SINCE THEY WILL BE NEEDED FOR PROOF OF DAMAGE.

Make sure the Bill of Lading is properly completed showing a detailed list of all services and charges. Once you agree with all the services and charges listed on the Bill of Lading, sign all required paperwork. DO NOT SIGN ANY BLANK FORMS. You may note on the Bill of Lading or the inventory sheet any damages discovered; however, a damage claim form is still required. Be sure to get a copy of the Bill of Lading, the Addendum to the Bill of Lading, and the inventory (if one was performed).

XIII. LOSS OR DAMAGE

If you have lost or damaged items, contact your mover for a claim form. Claims will not be processed until you pay for the move in full. CLAIMS SHOULD BE FILED WITH THE MOVER AS SOON AS POSSIBLE, BUT <u>NO LATER THAN NINE MONTHS</u> AFTER DELIVERY. DO NOT DISPOSE OF ANY DAMAGED ITEMS OR THE PACKING MATERIALS USED FOR THOSE ITEMS SINCE THEY WILL BE NEEDED FOR PROOF OF DAMAGE.

On the claim form, list all damaged and lost items, including the age, original cost, and weight as well as a description of the damage. The mover may request estimates or may send a third party to assess the damages.

All claims will be settled based upon the type of valuation you selected on the Bill of Lading and the Addendum to the Bill of Lading (see Valuation section above). If you are unable to resolve your claim with the mover, the Public Staff's Transportation Rates Division (919-733-7766) is available to assist you. If the mover denies liability for all or part of your claim, you may seek legal action against the mover. However, such action must be taken within two years and one day from the date when written notice was given by the mover to you that your claim has been denied. Items believed to be stolen should be reported to the proper law enforcement authorities immediately.

XIV. HAVE A GREAT MOVE!

We hope this information will be helpful to you in your selection of a Commission-certificated mover and in understanding the various aspects of the move you are about to experience. Yes, moving is stressful. However, the more educated you are about the moving industry and your rights and responsibilities, the more likely your move will go as smoothly as possible.

This information was developed as a coordinated effort by the North Carolina Utilities Commission, the Public Staff of the Commission, and the North Carolina Movers Association. Let us know if you have any questions or suggestions about improvements to this document by calling the Public Staff's Transportation Rates Division at 919-733-7766. We are always interested in learning ways to help our citizens!

DOCKET NO. T-100, SUB 93

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Public Staff – North Carolina Utilities	)	
Commission's Petition for Uniform Procedure	)	
to Adjust Intrastate Fuel Surcharge Applicable	)	ORDER ADOPTING RULE R2-16.2
to Common Carriers of Household Goods	)	

BY THE COMMISSION: On December 11, 2013, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a petition (including a proposed Rule R2-16.2) requesting that the Commission modify the procedure currently being used to adjust the household goods (HHG) carrier fuel surcharge applicable to intrastate weight/distance moves (moves greater than 35 miles, measured from the point of origin of shipment to destination).

The Public Staff, in support of its petition, stated as follows:

1. In its Order issued January 18, 1991, in Docket No. M-100, Sub 121, the Commission established procedural guidelines for applications by regulated common carriers for a fuel surcharge based on an historical index price. The procedure set forth in Appendix A of the Order permits any common carrier to apply for approval of a fuel surcharge, with the application specifying the initial value of the index price. An application filed by Thursday is to be considered at the Commission's staff conference the following Monday. If approved, the surcharge is effective the following Wednesday. Changes in the surcharge may be filed by carriers, the Public Staff, or the Attorney General.

2. On March 28, 2000, in Docket No. T-825, Sub 334, the North Carolina Movers Association, Inc. (NCMA), and the North Carolina Trucking Association, Inc., filed requests for a fuel surcharge and provided supporting documentation including a Fuel Surcharge Index Chart, as required by the guidelines established in Docket No. M-100, Sub 121. The filings included documentation for calculating the ratio of gasoline to diesel in developing the composite index cost of fuel: 19.46% for gasoline and 80.54% for diesel fuel.

3. On February 22, 2002, in Docket No. T-100, Sub 49, the Commission issued an Order exempting from regulation the transportation of household goods within North Carolina and providing that the Commission would issue certificates of exemption with certain requirements instead of certificates of public convenience and necessity to movers of household goods. On December 20, 2002, in the same docket, the Commission issued an Order establishing the Maximum Rate Tariff No. 1 (MRT) and stating that the current fuel surcharge procedure would continue to apply under the MRT.

4. Both prior to and after the implementation of the MRT, the fuel surcharge applied only when transportation charges were based on the weight of the shipment and the distance from origin to destination. The Commission denied a request for a fuel surcharge for hourly-rated moves by Order issued April 1, 2010, in Docket No. T-825, Sub 343.

5. Currently, the fuel surcharge for carriers of household goods is a simple calculation based on the base composite index cost of fuel ($0.933) and the current composite index price of fuel based on the United States Department of Energy - Energy Information Administration (EIA), On-Highway Diesel Fuel Price Index and Retail Gasoline Price Index for the Lower Atlantic Region. The EIA information is posted for public review each Monday afternoon or Tuesday morning, except on holidays, when it is generally available the next working day. The EIA information is evaluated by the Public Staff each week, and an appropriate fuel surcharge is determined using the Household Goods Fuel Surcharge Index Chart filed on October 6, 2005, in Docket No. T-825, Sub 339.

6. The standard practice has been for a certificated household goods carrier to file a request for a surcharge increase or for the Public Staff to file a request for a surcharge decrease based on the weekly review of the EIA information. In either case, the Public Staff submits an agenda item for consideration on the Commission's Staff Conference agenda published the Wednesday preceding the Staff Conference where the request will be heard. If the request is approved at Staff Conference, the Order is issued the day after the Staff Conference. These requests for adjustment do not occur on a defined, regular basis, but when a certificated household goods carrier or the Public Staff believes an adjustment is needed.

7. The Public Staff is unaware of any occasion where the request for adjustment of the fuel surcharge has been opposed by any party.

8. The Public Staff believes that the public and household goods carriers would benefit if the adjustment of the fuel surcharge occurred on a more predictable, regular basis without the necessity of submitting an agenda item to the Commission for review at its Staff Conference.

9. The Public Staff proposes that the procedure set forth in the attached rule be adopted by the Commission to replace the current fuel surcharge procedure. The procedure proposed in the rule would provide for monthly adjustment of the fuel surcharge. On the last Tuesday of each month, the Public Staff would file its proposed surcharge with supporting calculations in the annual fuel surcharge docket, where it would be available for review by the public and other interested parties. The Commission would issue an order adjusting the fuel surcharge no later than the first business day of the following week.

> 10. The NCMA has authorized the Public Staff to indicate that it supports this petition. As the NCMA represents the majority of certificated carriers of household goods in North Carolina, the Public Staff believes that an expedited comment cycle is appropriate, with initial comments due in 21 days and reply comments due in seven days. The NCMA also supports these proposed deadlines.

On March 17, 2014, the Commission issued an Order Requesting Comments. This Order established dates for Commission-certificated HHG carriers, the Public Staff, the NCMA, the Office of the Attorney General, and other interested parties to file comments and reply comments on the proposed rule.

On April 11, 2014, the NCMA filed comments stating that it supports the Public Staff's proposal. No other comments or reply comments were filed with the Commission.

In support of the Public Staff's proposal, the NCMA, which represents over 150 Commission-certificated HHG carriers, commented as follows:

> Fuel surcharge changes have always been approved by the NCUC without any opposition since the March 28, 2000 order for Docket T-825, Sub 334. The process would be streamlined by not having the Public Staff or a certificated carrier file requests that require approval at the Staff Conference.
>
> It will also be advantageous for the adjustments to the fuel surcharge to be made on a regular, predictable basis. The carriers would always know when the changes are going to occur and would be provide [*sic*] the shippers with the appropriate fuel surcharge.

DISCUSSION AND CONCLUSIONS

The Commission-approved fuel surcharge mechanism allows movers to efficiently and fairly adjust the level of fuel costs recoverable through rates in response to fuel price fluctuations. No issues have been raised in this proceeding regarding the actual formula that has been established for calculating the fuel surcharge rate. Instead, the focus of the Public Staff's petition is on the procedural process for approving changes in the fuel surcharge.

Presently, under the current fuel surcharge procedure, at varying time intervals, the Public Staff, after having determined that a fuel surcharge adjustment is in order (or after having reached a conclusion regarding the appropriateness of a proposed adjustment submitted by another party), presents its recommendation at a North Carolina Utilities Commission Staff Conference where the Commission decides whether to approve the Public Staff's recommendation. Upon approval of the proposed adjustment, the Commission issues an order reflecting that decision.

Under the Public Staff's proposed change to the present procedure, the Public Staff would determine the appropriate fuel surcharge once per month and would file its recommendation in the annual fuel surcharge docket on the last Tuesday of each month (or the next business day thereafter if delayed by a legal State or Federal holiday). Thereafter, on the first business day of the week following the Public Staff's filing, the Commission would issue an order adjusting the fuel surcharge, presumably, if appropriate.

The Commission has carefully reviewed and considered the proposed rule and the supporting arguments presented by the Public Staff and the NCMA. The Commission finds good cause to adopt Rule R2-16.2, as requested by the Public Staff, for the reasons set forth by the Public Staff and the NCMA. However, the Commission finds and concludes that the proposed Rule should be slightly modified to reflect that the Commission will issue an order adjusting the fuel surcharge when an adjustment is appropriate. Accordingly, the Commission is of the opinion that subsection (a)(2) of the Public Staff's proposed rule should be modified to be worded as follows:

> On the first business day of the week following the Public Staff's filing, the Commission will issue an order adjusting the fuel surcharge when an adjustment is appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R2-16.2, as set forth in Appendix A attached hereto, is hereby adopted and shall be effective as of the date of this Order.

2. That a copy of this Order shall be served by the Chief Clerk's Office to all Commission-certificated household goods carriers.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of June, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

APPENDIX A
Page 1 of 1

RULE R2-16.2 HOUSEHOLD GOODS CARRIER FUEL SURCHARGE

(a) A fuel surcharge for household goods carriers shall be established by the Commission on a monthly basis using the following procedure:

(1) On the last Tuesday of each month (or the next business day thereafter if delayed by a legal State or Federal holiday), the Public Staff shall file its recommended fuel surcharge in the current calendar year fuel surcharge docket (T-825). The recommended fuel charge shall be calculated by the Public Staff as follows:

a. Using the On-Highway Diesel Fuel Price Index and Retail Gasoline Price Index for the Lower Atlantic Region released that week by the United States Department of Energy - Energy Information Administration (EIA), or another source approved by the Commission, the Public Staff shall determine a current composite cost of fuel using the diesel/gasoline ratio shown in Schedule 2-A filed in Docket No. T-825, Sub 334, on March 28, 2000.

b. With this composite cost of fuel, the Public Staff shall determine the appropriate fuel surcharge using the Fuel Surcharge Index Chart filed on October 6, 2005, in Docket No. T-825, Sub 339, to be applied per bill of lading mile for all North Carolina intrastate household goods moves governed by the Commission's most recently issued Maximum Rate Tariff in accordance with the procedures outlined in Docket No. M-100, Sub 121, and the provisions of Appendix A, Paragraph C, of the Order dated January 18, 1991.

(2) On the first business day of the week following the Public Staff's filing, the Commission will issue an order adjusting the fuel surcharge when an adjustment is appropriate.

(b) All fuel surcharge revenue assessed and collected shall be passed on or otherwise credited to the purchaser of the fuel. The fuel surcharge shall be assessed once per shipment regardless of the number of vehicles used.

DOCKET NO. W-100, SUB 54

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Rulemaking to Implement G.S. 62-133.12, North Carolina Session Law 2013-106 (House Bill 710)	)))	ORDER ADOPTING RULES TO IMPLEMENT G.S. 62-133.12

BY THE COMMISSION: On August 21, 2013, the Public Staff filed a Petition for Order Establishing Rulemaking Proceeding in this docket. In the Petition, the Public Staff requested that the Commission establish a rulemaking to implement G.S. 62-133.12, enacted by North Carolina Session Law 2013-106 (House Bill 710), and adopt the proposed rules that the Public Staff attached to the Petition with such modifications as may be appropriate in light of any comments that might be presented during the rulemaking proceeding. The draft rules established procedures for determining and implementing the rate adjustment mechanisms contemplated in the provisions in G.S. 62-133.12, i.e., a Water System Improvement Charge (WSIC) and a Sewer System Improvement Charge (SSIC).

On August 22, 2013, and August 23, 2013, respectively, Aqua North Carolina, Inc. (Aqua), and Utilities, Inc. (UI), the parent company of Carolina Water Service, Inc. of North Carolina (CWS) and five other regulated water and/or wastewater utilities in North Carolina, filed petitions to intervene in this docket. In support of its Petition, Aqua stated that it had filed a general rate case in Docket No. W-218, Sub 363 on August 2, 2013, and that, pursuant to the authority granted in the newly enacted G.S. 62-133.12, Aqua had requested that the Commission approve a rate adjustment mechanism in that rate proceeding to allow Aqua to recover reasonable and prudent investments in eligible water and sewer system improvements. UI stated that its subsidiary CWS had filed a general rate case in Docket No. W-354, Sub 336 on June 28, 2013, with a similar request.

On August 28, 2013, the Commission issued an Order Establishing Rulemaking and Granting Petitions of Aqua and Utilities, Inc., to Intervene. This order established dates for the parties to file comments and reply comments on the proposed rules.

On October 7, 2013, Aqua and UI filed joint Initial Comments and stated that Aqua and UI planned to negotiate with the Public Staff on the proposed rules.

On November 8, 2013, the Public Staff, Aqua, and UI (Joint Movants) filed a Joint Motion Requesting Approval of Rules. In support of the Joint Motion, the Joint Movants stated that they had reached agreement on the recommended WSIC Rule R7-39 and SSIC Rule R10-26, which were attached thereto as Exhibit A and B, respectively. The Joint Movants also stated that they believed the recommended rules would ensure that the objectives of G.S. 62-133.12 are maintained and provide for effective implementation, continued stringent regulatory review and oversight, and appropriate consumer protections. Further, Joint Movants noted that that the semi-annual adjustments proposed in the rules would reasonably reduce regulatory lag and provide for efficient administration of these rate adjustments, but not result in an excessive frequency of rate adjustments. Joint Movants also observed that the recommended WSIC Rule R7-39 and SSIC Rule R10-26 were identical with the exceptions of the interchangeable words WSIC and SSIC, water and sewer, and water quality and effluent. Lastly, the Joint Movants noted that Aqua and UI are provided different "WSIC Periods" and "SSIC Periods" in subparagraphs (b)(7) in order to expedite the Public Staff review and Commission approvals of the semi-annual adjustments described in paragraph (i).

The Commission takes judicial notice that, as stated in the petitions to intervene, Aqua and CWS filed general rate cases shortly after the General Assembly adopted G.S. 62-133.12 requesting that the Commission approve WSIC and SSIC rate adjustment mechanisms in each case. Numerous hearings were held across the State to allow the public to comment on the rate increase and WSIC/SSIC rate adjustment requests. In each docket, various customers testified in opposition to Commission approval of a WSIC/SSIC rate adjustment mechanism. Much of the customer opposition stemmed from the belief that the mechanism would be devoid of stringent regulatory oversight and would allow the company to implement and collect the adjustment without customer input or knowledge.

The Commission noted in the Aqua and CWS rate cases that the General Assembly recognized a need in North Carolina and adopted the rate adjustment mechanisms in G.S. 62-133.12 to incentivize water and sewer utilities to invest in needed water and sewer infrastructure improvements. In its order in the Aqua rate case, for example, the Commission stated as follows:

> The Commission believes that the primary purpose of G.S. 62-133.12 was to encourage and accelerate investment in needed water and sewer infrastructure by means of a mechanism which will alleviate the effects of regulatory lag by allowing for earlier recovery of some portion, not to exceed 5% of approved service revenues, of the incremental depreciation and capital costs associated with eligible investments made between general rate case proceedings. In accordance with G.S. 62-133.12, eligible water system and sewer system improvements would be installed, for example, to comply with primary drinking water standards, to implement solutions to wastewater problems, and to comply with State and federal law and regulations. Further, G.S. 62-133.12 allows, upon the Commission's specific direction, for the utility to implement solutions to comply with otherwise non-mandatory secondary water quality standards.
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> The Commission believes that Aqua will be incentivized and encouraged to accelerate its investment in water and sewer infrastructure improvements to comply with applicable water quality and effluent standards, including secondary water quality standards, if authorized to utilize a WSIC/SSIC mechanism to alleviate the effects of regulatory lag. … Providing an incentive to Aqua to undertake more extensive improvements to address secondary water quality issues in those individual subdivision service areas which have, for example, iron and manganese concentration levels that exceed federal and state standards which have not been sufficiently remedied on a sustained basis by past treatment methods, benefits the Company's customers. Moreover, the recovery mechanism is of further benefit to customers because it will be available to fund projects to address problematic systemic secondary water quality issues should the Commission direct the Company

> to undertake them in individual subdivision service areas, even though such projects may not be specifically required by federal and/or state standards and might not be high priority to the Company absent the direction of the Commission. The Commission determines that some secondary water quality improvement projects generally may have been given lower priority in the past by water utilities because limited available capital budget funds are spent first on primary water quality improvements. The availability of the WSIC recovery mechanism should, to customer benefit, provide the Company with increased incentive and wherewithal to address secondary water quality issues on a sustained basis and sooner than it would otherwise be able.
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> …
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> With respect to the timing of cost recovery of infrastructure improvements, the Commission believes that, to the extent that necessary investments would result in rate increases at some point in time irrespective of the mechanism, customers will benefit from the rate-smoothing effects of more gradual increases made possible by recovery through a WSIC/SSIC surcharge. Furthermore, if the ability to increase rates to recover certain costs between general rate cases actually results in fewer or less frequent rate cases as claimed by the Company, ratepayers would benefit from lower rates because the Company's recoverable expenses would be reduced by the elimination of the substantial costs associated with the preparation and litigation of a general rate case.

The Commission has carefully reviewed and considered the proposed rules, the arguments for and against the rate adjustment mechanisms, the input received from customers during the Aqua and CWS public hearings, the joint recommendations of the parties to this proceeding, and the record proper. Based upon this review, the Commission concludes that the recommended rules would, for the most part, ensure that the objectives of G.S. 62-133.12 are maintained and provide for effective implementation. The Commission is not convinced, however, that the rules as proposed in this proceeding would adequately address the concerns raised by consumers during the public hearings in the Aqua and CWS rate cases. In the Commission's opinion, the proposed rules could be strengthened to address those concerns: (1) by requiring the utility to provide advanced notice of the potential dollar impact that the proposed adjustment might have on the average customer's monthly utility bill if the requested rate adjustment mechanism and rate increase are granted in the rate proceeding; (2) by requiring the utility to notify the Commission 60 days in advance of the effective date of any WSIC/SSIC rate adjustment; (3) by requiring the Public Staff to provide 15 days' notice to the Commission before a WSIC/SSIC adjustment is submitted to the Commission for consideration at a regularly scheduled staff conference; and (4) by informing parties interested in receiving notice of these filings that they may subscribe to the Commission's electronic notification system.

While approving WSIC and SSIC rate adjustment mechanisms for the utilities in the Aqua and CWS rate cases, the Commission modified the utilities' proposals in order to address concerns raised by customers at the public hearings and other parties. The rules adopted herein for all regulated water and sewer companies retain the procedural safeguards and requirements imposed in those cases. As further stated in the Aqua rate case order, for example,

> the rate adjustments related to the WSIC/SSIC mechanism are not automatic. Prior to the initiation of each surcharge, the Company must obtain approval from the Commission. Aqua may file a request with the Commission for authority to impose the WSIC and/or SSIC mechanism to be effective no less than 60 days after filing the request. Prior to the requested effective date of the mechanism, the Public Staff will present the Company's request for Commission consideration at a regularly scheduled staff conference. Based upon its detailed review and investigation, the Public Staff will recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed WSIC/SSIC.

Moreover, any request for cost recovery through the mechanisms will be thoroughly reviewed. As the Commission stated in the Aqua rate case order,

> The eligible system improvements must be completed and placed in service prior to the Company requesting approval; as a result, actual cost data and other pertinent information will be available for review and analysis. The Public Staff will review and scrutinize such information to determine whether the specific system improvements to be included in the requested surcharge are eligible for recovery through the WSIC/SSIC mechanism, pursuant to G.S. 62-133.12, before customers are actually charged under the mechanism. … Consequently, the Commission determines that the Public Staff, in its role as the consumer advocate, will carefully review and scrutinize each project proposed for recovery through the WSIC/SSIC mechanism for eligibility and reasonableness before providing its recommendation to the Commission.
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> Further, the requirement in the alternative procedures for Aqua to provide an ongoing three-year plan which includes a description of all proposed eligible system improvements, including an estimate of the cost of the improvements and dates when the improvements will be placed into service will allow the Public Staff to review such filings and have discussions with Aqua concerning such proposed improvements prior to the Company expending the funds and requesting ratepayer recovery through the WSIC/SSIC mechanism. The Public Staff's scrutiny and review of the ongoing three-year plan between general rate case filings and its routine discussions with Aqua concerning the same, would provide the Public Staff with detailed information concerning eligible system improvement projects for which Aqua may eventually seek WSIC or SSIC recovery and should also keep the Public Staff more informed regarding matters concerning the quality of service provided by Aqua to its customers.
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> …
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> The Commission determines that the procedures provided in Appendices C and D should provide ample regulatory oversight of the WSIC/SSIC mechanism for the protection of the customers. All infrastructure improvements will be reviewed by the Public Staff and the Commission to determine whether they are eligible for cost recovery through the WSIC/SSIC mechanism and will be reviewed again for prudency and reasonableness in the Company's next general rate case proceeding.

Furthermore, any rate adjustments authorized under the WSIC and SSIC mechanisms outside of a general rate case will be allowed to become effective, but not unconditionally approved. In other words, the adjustments will be provisional, will not be deemed prima facie just and reasonable, and, thus, may be rescinded retroactively in the utility's subsequent general rate case, at which time the adjustment may be further examined for a determination of its justness and reasonableness. As the Commission noted in the Aqua rate case order:

> The Commission finds that while an approved mechanism will allow cost recovery resulting in limited or capped rate increases between general rate cases, Aqua is not unconditionally guaranteed recovery of such costs. WSIC/SSIC surcharges are subject to Commission review and scrutiny for reasonableness and prudency in general rate case proceedings as has been the case for investments and expenses prior to the enactment of G.S. 62-133.12. Consequently, the Commission continues to have authority in a general rate case proceeding to disallow costs related to investments in water and sewer improvements recovered under the WSIC/SSIC mechanism that were subsequently determined to be unreasonable or imprudent. The Commission is unpersuaded that the WSIC/SSIC mechanism will discourage Aqua from investing in projects that are efficient and economical but not eligible for the favorable accelerated recovery, as asserted by the Attorney General, because the Company's investment decisions remain subject to the reasonable and prudent standard set forth in G.S. 62-133 and such investments will be scrutinized by the Public Staff and the Commission in a general rate case proceeding. Any costs deemed to be unreasonable or imprudent upon review by the Public Staff and the Commission will be disallowed.

As Public Staff witness Fernald testified in the Aqua rate case,

> due to the detailed examination which would occur with respect to the specific plant additions reviewed between rate case proceedings in regard to the WSIC/SSIC mechanism, those same plant additions would likely not require as much review in a general rate case proceeding, but would nonetheless be subject to further review. Consequently, the Commission determines that the Public Staff, in its role as the consumer advocate, will carefully review and scrutinize each project proposed for recovery through the WSIC/SSIC mechanism for eligibility and reasonableness before providing its recommendation to the Commission.

In response to the concerns raised in the Aqua and CWS rate cases about the utility's ability to impose new charges without any notice to customers or public hearings, the WSIC and SSIC rate adjustment mechanisms adopted in the Aqua and CWS rate cases and the rules adopted herein provide that any utility customer will have the opportunity to participate if they so choose in proceedings when rate adjustments are proposed to be made. Again, as noted in the Aqua rate case order, the WSIC and SSIC rate adjustment mechanisms adopted therein

> require that Aqua file a request with the Commission for authority to impose the WSIC/SSIC mechanism once the eligible system improvements are in service. The effective date of the WSIC/SSIC would be no less than 60 days after filing the request. Such request must also be provided to the Public Staff. Other parties

interested in receiving notice of Aqua's request to impose the WSIC/SSIC mechanism may subscribe to the Commission's electronic notification system, for Docket No. W-218, Sub 363A, through the Commission's website at www.ncuc.net.

As previously discussed, prior to the requested effective date of the mechanism, the Public Staff will present the Company's request for Commission consideration at a regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed WSIC/SSIC. Witness Roberts testified that customers may contact Aqua at any time to discuss the inclusion or exclusion of a specific project included on Aqua's three-year plan and that the Company is willing to meet with customers regarding any water quality concerns and associated remedies. Customers also may contact the Public Staff or file a formal complaint with the Commission regarding matters concerning their regulated utility service. All infrastructure improvements recovered through the WSIC/SSIC mechanism will be reviewed again by the Public Staff and the Commission for prudency and reasonableness in the Company's next general rate case proceeding. Customers may also express any concerns regarding the WSIC/SSIC mechanism to the Commission at that time. The Commission is of the opinion and therefore, so finds and concludes, that the foregoing procedure will provide adequate notice to interested parties and provide various opportunities for input by interested parties with respect to the proposed imposition of the WSIC/SSIC mechanism by Aqua between general rate case proceedings.

In summary, the Commission concludes that paragraph (d) in the proposed WSIC and SSIC rules shall be amended: (1) to reflect the potential dollar impact that the proposed adjustment might have on the average customer's monthly utility bill if the requested rate adjustment mechanism and rate increase are granted in the rate proceeding; and (2) to adopt a notice to that effect. Further, the Commission amends paragraph (f) in the WSIC and SSIC rules to reflect that: (1) the utility shall request approval of the proposed WSIC/SSIC adjustment at least 60 days in advance of the effective date of the rate change; (2) the Public Staff shall notify the Commission 15 days in advance before a WSIC/SSIC adjustment is submitted to the Commission for consideration at a regularly scheduled staff conference; and (3) parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system.

IT IS, THEREFORE, ORDERED that Rules R7-39 and R10-26, as set forth in Appendices A and B attached hereto, are hereby adopted effective as of the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the _6th__ day of June, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A
Page 1 of 6

R7-39 WATER SYSTEM IMPROVEMENT CHARGE MECHANISM

(a) Scope of Rule. – This rule provides the procedure for the approval and administration of a rate adjustment mechanism pursuant to G.S. 62-133.12 to allow a utility to recover the incremental depreciation expense and capital costs related to the utility's reasonable and prudently incurred investment in eligible water system improvements.

(b) Definitions. – As used in this rule:

(1) "Capital costs" means the pretax return on costs permitted to be capitalized pursuant to the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts, net of accumulated depreciation and accumulated deferred income taxes, using the current federal and state income tax rates and the utility's capital structure, cost of long-term debt, and return on equity approved in the utility's most recent general rate case.

(2) "Depreciation expense" means the annual depreciation accrual rates employed in the utility's most recent general rate case for the plant accounts in which the cost of each eligible water system improvement is recorded applied to the cost of eligible water system improvements.

(3) "Eligible water system improvements" means the improvements set forth in G.S. 62-133.12(c) and shall include only those improvements found necessary by the Commission to provide safe, reliable, and efficient service in accordance with applicable water quality standards.

(4) "Incremental depreciation expense and capital costs" means depreciation expense and capital costs that have been incurred since the utility's most recent rate case and have not been included in the utility's cost of service for ratemaking purposes.

(5) "Water System Improvement Charge or WSIC" means an adjustment to customer bills that allows a utility to recover the WSIC Revenue Requirement.

(6) "WSIC Revenue Requirement" means the annual revenue required to allow a utility to recover the annual incremental depreciation expense and capital costs of eligible water system improvements.

(7) "WSIC Period" means the 12-month period ended December 31 for Aqua North Carolina, Inc. and the 12-month period ended March 31 for Utilities, Inc., and its North Carolina affiliates. The WSIC Period for other water utilities shall be a 12-month period established by the Commission in conjunction with the approval of a WSIC mechanism for that utility.

(8) "WSIC mechanism" means a rate adjustment mechanism approved by the Commission in a general rate case pursuant to G.S. 62-133.12.

(c) Request for Water System Improvement Charge Mechanism. – A utility seeking approval of a WSIC mechanism shall include in its application for a general rate increase under G.S. 62-133 and Commission Rule R1-17 the following:

(1) A three-year plan that includes the following:

a. A detailed description of all proposed eligible water system improvements expected to be completed in the initial WSIC Period and an estimate of the cost of the improvements and dates when the improvements will be placed into service; and

b. A brief description of the proposed eligible water system improvements, estimated costs, and completion dates for improvements that the utility plans to complete during the two years following the initial WSIC Period.

(2) The proposed effective dates of the WSIC and semiannual adjustments to the charge.

(3) Testimony, affidavits, exhibits, or other evidence demonstrating that a WSIC is in the public interest and will enable the utility to provide safe, reliable, and efficient service in accordance with applicable water quality standards.

(4) Any other information required by the Commission.

(d) Customer Notice. – The notice to customers of the utility's general rate increase application shall include the proposed WSIC mechanism and the estimated impact of the charges under the mechanism on the utility's monthly service rates. The Notice shall include the following statement:

Water System Improvement Charge Mechanism

Pursuant to G.S. 62-133.12 and Commission Rule R7-39, the Company is requesting that the Commission approve a Water System Improvement Charge Mechanism. This mechanism will allow the Company to recover the annual incremental depreciation expense and capital costs of eligible water system improvements completed and placed in service between rate cases. In support of this request, the Company has filed a three-year plan with its application which list various projects which may be eligible for recovery pursuant to this mechanism, the cost and/or estimated costs of those projects, and the estimated completion date of those projects. By law, the cumulative maximum charges between rate cases that the Company can recover through the use of this mechanism cannot exceed five percent of the total service revenues that the Commission will approve in this rate case. Customers may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net to receive notification of any Company requests to utilize the Water System Improvement Charge Mechanism, if approved.

In this Application, the Company has requested that the Commission allow it to recover total service revenues of $____________. Five percent of these revenues is $____________. If the Commission permits the Company to recover the revenue requirements requested in the Application, the Company projects that the average monthly water bill for a typical residential customer (based upon monthly water usage of x,xxx gallons) would be $_______. Based upon these figures, the Company estimates that the maximum that the average residential customer's monthly water bill could be increased by this adjustment mechanism between rate cases is $________.

The Commission may eliminate or modify any rate adjustment mechanism approved in this case upon a finding that it is no longer in the public interest.

(e) General Rate Case Review. – Following notice and hearing, the Commission shall approve a WSIC mechanism only upon a finding that it is in the public interest.

(f) Initiation of Charge. – Once a WSIC mechanism is approved and eligible water system improvements are in service, the utility may file a request with the Commission for authority to impose the water system improvement charge pursuant to the mechanism, to be effective no less than 60 days after filing the request. The Company shall also provide a copy of the request to the Public Staff.[1] Prior to the effective date, the Public Staff shall schedule the request for Commission consideration at the regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed water system improvement charge. The Public Staff shall formally notify the Commission at least 15 days in advance of the date that the request shall be scheduled for Commission consideration at the regularly scheduled staff conference.

[1] Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

APPENDIX A
Page 4 of 6

(g) Computation of the WSIC Revenue Requirement. – The WSIC Revenue Requirement shall be computed for each WSIC Period as follows:

Eligible water system improvements	$X,XXX,XXX
Less: Accumulated depreciation	X,XXX,XXX
Less: Accumulated deferred income taxes	X,XXX,XXX
Net plant investment	$X,XXX,XXX
Pre-tax rate of return	X.XX%
Capital costs	$X,XXX,XXX
Plus: Depreciation expense	XXX,XXX
Subtotal, excluding regulatory fee	$X,XXX,XXX
Regulatory fee gross-up factor	XXXX
Total	$X,XXX,XXX

(h) Computation of Water System Improvement Charge. –

(1) The WSIC shall be expressed as a percentage carried to two decimal places and shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

(2) The WSIC shall be computed by dividing the annual WSIC Revenue Requirement by the projected revenues of the utility during the 12-month period following implementation of the charge.

(i) Semiannual Adjustments. – A utility may file a request for a WSIC adjustment no more frequently than semiannually.

(1) The request shall include the computation and supporting data for the adjustment.

(2) Cumulative WSIC Revenue Requirements may not exceed five percent of the total annual service revenues approved in the utility's last general rate proceeding.

(3) The procedural requirements set forth in subsection (f) of this Rule shall apply to requests for semiannual adjustments.

(j) Experience Modification Factor. – The WSIC shall be modified through the use of an experience modification factor (EMF) that reflects the difference between the WSIC Revenue Requirement and the revenues that were actually realized under the WSIC during the WSIC Period. The EMF shall remain in effect for a 12-month period. Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred costs of the utility for eligible water system improvements to be refunded to a utility's customers through operation of the EMF shall include an amount of interest at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

APPENDIX A
Page 5 of 6

(k) Water System Improvement Charge Reset. – The WSIC shall be reset at zero as of the effective date of new base rates established in the utility's general rate case. Thereafter, only the incremental depreciation expense and capital costs of new eligible water system improvements that have not previously been reflected in the utility's rates shall be recoverable through the WSIC.

(l) Audit and Reconciliation. – The WSIC shall be subject to the following:

(1) Within 60 days following the end of each WSIC Period, each utility shall file a report, in a format prescribed by the Commission, reconciling its actual eligible water system improvement costs, actual WSIC revenues, and EMF computation.

(2) The Public Staff shall audit the utility's actual eligible water system improvement costs, actual WSIC revenues, and EMF computation, and shall file a report on its audit no later than four months after the end of the WSIC Period of the utility.

(m) Ongoing Three-Year Plan. – Within 60 days following the end of each WSIC Period, the utility shall file an updated three-year plan containing the information prescribed in Section (c)(1) of this Rule and any other information required by the Commission.

(n) Quarterly Filings with the Commission. – Within 45 days after the end of each calendar quarter, the utility shall file the following reports:

(1) A quarterly earnings report consisting of the following:

a. A balance sheet and income statement for the calendar quarter and calendar year to date for the utility;

b. A statement of the per books net operating income for the calendar quarter and calendar year to date for each rate division of the utility based on North Carolina ratemaking;

c. A statement of rate base at the end of the calendar quarter for each rate division of the utility based on North Carolina ratemaking; and

d. The number of customers and gallons sold for each month of the calendar quarter for each rate division by rate type (meter size, flat rate, etc.).

(2) A quarterly report of WSIC collections from customers consisting of amounts collected for the quarter by rate division and rate type.

(3) A construction status report which includes by rate division the following information for each eligible water system improvement project:

a. The costs incurred during the quarter;

b. The cumulative amount incurred;

c. The estimated total cost for each project;

d. The estimated completion date; and

e. The actual completion date.

(o) Elimination or Modification of WSIC Mechanism. – After notice to the utility and opportunity to be heard, the Commission may eliminate or modify any previously authorized WSIC mechanism upon a finding that it is not in the public interest.

(p) Burden of Proof. – The burden of proof as to whether a WSIC mechanism is in the public interest, the correctness and reasonableness of any WSIC, and whether the investment in the water system improvements was reasonable and prudently incurred shall be on the utility.

APPENDIX B
Page 1 of 6

R10-26 SEWER SYSTEM IMPROVEMENT CHARGE MECHANISM

(a) Scope of Rule. – This rule provides the procedure for the approval and administration of a rate adjustment mechanism pursuant to G.S. 62-133.12 to allow a utility to recover the incremental depreciation expense and capital costs related to the utility's reasonable and prudently incurred investment in eligible sewer system improvements.

(b) Definitions. – As used in this rule:

(1) "Capital costs" means the pretax return on costs permitted to be capitalized pursuant to the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts, net of accumulated depreciation and accumulated deferred income taxes, using the current federal and state income tax rates and the utility's capital structure, cost of long-term debt, and return on equity approved in the utility's most recent general rate case.

(2) "Depreciation expense" means the annual depreciation accrual rates employed in the utility's most recent general rate case for the plant accounts in which the cost of each eligible sewer system improvement is recorded applied to the cost of eligible sewer system improvements.

(3) “Eligible sewer system improvements” means the improvements set forth in G.S. 62-133.12(d) and shall include only those improvements found necessary by the Commission to provide safe, reliable, and efficient service in accordance with applicable effluent standards.

(4) “Incremental depreciation expense and capital costs” means depreciation expense and capital costs that have been incurred since the utility’s most recent rate case and have not been included in the utility’s cost of service for ratemaking purposes.

(5) “Sewer System Improvement Charge or SSIC” means an adjustment to customer bills that allows a utility to recover the SSIC Revenue Requirement.

(6) “SSIC Revenue Requirement” means the annual revenue required to allow a utility to recover the annual incremental depreciation expense and capital costs of eligible sewer system improvements.

(7) “SSIC Period” means the 12-month period ended December 31 for Aqua North Carolina, Inc. and the 12-month period ended March 31 for Utilities, Inc., and its North Carolina affiliates. The SSIC Period for other sewer utilities shall be a 12-month period established by the Commission in conjunction with the approval of a SSIC mechanism for that utility.

(8) “SSIC mechanism” means a rate adjustment mechanism approved by the Commission in a general rate case pursuant to G.S. 62-133.12.

(c) Request for Sewer System Improvement Charge Mechanism. – A utility seeking approval of a SSIC mechanism shall include in its application for a general rate increase under G.S. 62-133 and Commission Rule R1-17 the following:

(1) A three-year plan that includes the following:

a. A detailed description of all proposed eligible sewer system improvements expected to be completed in the initial SSIC Period and an estimate of the cost of the improvements and dates when the improvements will be placed into service; and

b. A brief description of the proposed eligible sewer system improvements, estimated costs, and completion dates for improvements that the utility plans to complete during the two years following the initial SSIC Period.

(2) The proposed effective dates of the SSIC and semiannual adjustments to the charge.

(3) Testimony, affidavits, exhibits, or other evidence demonstrating that a SSIC is in the public interest and will enable the utility to provide safe, reliable, and efficient service in accordance with applicable effluent standards.

(4) Any other information required by the Commission.

(d) Customer Notice. – The notice to customers of the utility's general rate increase application shall include the proposed SSIC mechanism and the estimated impact of charges under the mechanism on the utility's monthly service rates. The Notice shall include the following statement:

Sewer System Improvement Charge Mechanism

Pursuant to G.S. 62-133.12 and Commission Rule R10-26, the Company is requesting that the Commission approve a Sewer System Improvement Charge Mechanism. This mechanism will allow the Company to recover the annual incremental depreciation expense and capital costs of eligible sewer system improvements completed and placed in service between rate cases. In support of this request, the Company has filed a three-year plan with its Application which list various projects which may be eligible for recovery pursuant to this mechanism, the cost and/or estimated costs of those projects, and the estimated completion date of those projects. By law, the cumulative maximum charges between rate cases that the Company can recover through the use of this mechanism cannot

APPENDIX B
Page 3 of 6

exceed five percent of the total service revenues that the Commission will approve in this rate case. Customers may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net to receive notification of any Company requests to utilize the Sewer System Improvement Charge Mechanism, if approved.

In this Application, the Company has requested that the Commission allow it to recover total service revenues of $____________. Five percent of these revenues is $____________. If the Commission permits the Company to recover the revenue requirements requested in the Application, the Company projects that the average monthly sewer bill for a typical residential customer (based upon monthly water usage of x,xxx gallons) would be $_______. Based upon these figures, the Company estimates that the maximum that the average residential customer's monthly sewer bill could be increased by this adjustment mechanism between rate cases is $________.

The Commission may eliminate or modify any rate adjustment mechanism approved in this case upon a finding that it is no longer in the public interest.

(e) General Rate Case Review. – Following notice and hearing, the Commission shall approve a SSIC mechanism only upon a finding that it is in the public interest.

(f) Initiation of Charge. – Once a SSIC mechanism is approved and eligible sewer system improvements are in service, the utility may file a request with the Commission for authority to impose the sewer system improvement charge pursuant to the mechanism, to be effective no less than 60 days after filing the request. The Company shall also provide a copy of the request to the Public Staff.[1] Prior to the effective date, the Public Staff shall schedule the request for Commission consideration at the regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed sewer system improvement charge. The Public Staff shall formally notify the Commission at least 15 days in advance of the date that the request shall be scheduled for Commission consideration at the regularly scheduled staff conference.

(g) Computation of the SSIC Revenue Requirement. – The SSIC Revenue Requirement shall be computed for each SSIC Period as follows:

Eligible sewer system improvements	$X,XXX,XXX
Less: Accumulated depreciation	X,XXX,XXX
Less: Accumulated deferred income taxes	X,XXX,XXX
Net plant investment	$X,XXX,XXX
Pre-tax rate of return	X.XX%
Capital costs	$X,XXX,XXX
Plus: Depreciation expense	XXX,XXX
Subtotal, excluding regulatory fee	$X,XXX,XXX
Regulatory fee gross-up factor	XXXX
Total	$X,XXX,XXX

(h) Computation of Sewer System Improvement Charge. –

(1) The SSIC shall be expressed as a percentage carried to two decimal places and shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

(2) The SSIC shall be computed by dividing the annual SSIC Revenue Requirement by the projected revenues of the utility during the 12-month period following implementation of the charge.

[1] Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

(i) Semiannual Adjustments. – A utility may file a request for a SSIC adjustment no more frequently than semiannually.

(1) The request shall include the computation and supporting data for the adjustment.

(2) Cumulative SSIC Revenue Requirements may not exceed five percent of the total annual service revenues approved in the utility's last general rate proceeding.

(3) The procedural requirements set forth in subsection (f) of this Rule shall apply to requests for semiannual adjustments.

(j) Experience Modification Factor. – The SSIC shall be modified through the use of an experience modification factor (EMF) that reflects the difference between the SSIC Revenue Requirement and the revenues that were actually realized under the SSIC during the SSIC Period. The EMF shall remain in effect for a 12-month period. Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred costs of the utility for eligible sewer system improvements to be refunded to a utility's customers through operation of the EMF shall include an amount of interest at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(k) Sewer System Improvement Charge Reset. – The SSIC shall be reset at zero as of the effective date of new base rates established in the utility's general rate case. Thereafter, only the incremental depreciation expense and capital costs of new eligible sewer system improvements that have not previously been reflected in the utility's rates shall be recoverable through the SSIC.

(l) Audit and Reconciliation. – The SSIC shall be subject to the following:

(1) Within 60 days following the end of each SSIC Period, each utility shall file a report, in a format prescribed by the Commission, reconciling its actual eligible sewer system improvement costs, actual SSIC revenues, and EMF computation.

(2) The Public Staff shall audit the utility's actual eligible sewer system improvement costs, actual SSIC revenues, and EMF computation, and shall file a report on its audit no later than four months after the end of the SSIC Period of the utility.

(m) Ongoing Three-Year Plan.–Within 60 days following the end of each SSIC Period, the utility shall file an updated three-year plan containing the information prescribed in Section (c)(1) of this Rule and any other information required by the Commission.

(n) Quarterly Filings with the Commission. – Within 45 days after the end of each calendar quarter, the utility shall file the following reports:

(1) A quarterly earnings report consisting of the following:

a. A balance sheet and income statement for the calendar quarter and calendar year to date for the utility;

b. A statement of the per books net operating income for the calendar quarter and calendar year to date for each rate division of the utility based on North Carolina ratemaking;

c. A statement of rate base at the end of the calendar quarter for each rate division of the utility based on North Carolina ratemaking; and

d. The number of customers and gallons sold for each month of the calendar quarter for each rate division by rate type (meter size, flat rate, etc.).

(2) A quarterly report of SSIC collections from customers consisting of amounts collected for the quarter by rate division and rate type.

(3) A construction status report which includes by rate division the following information for each eligible system improvement project:

a. The costs incurred during the quarter;

b. The cumulative amount incurred;

c. The estimated total cost of each project;

d. The estimated completion date; and

e. The actual completion date.

(o) Elimination or Modification of SSIC Mechanism. – After notice to the utility and opportunity to be heard, the Commission may eliminate or modify any previously authorized SSIC mechanism upon a finding that it is not in the public interest.

(p) Burden of Proof. – The burden of proof as to whether a SSIC mechanism is in the public interest, the correctness and reasonableness of any SSIC, and whether the investment in the sewer system improvements was reasonable and prudently incurred shall be on the utility.

DOCKET NO. E-22, SUB 489

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power for Registration of a New Renewable Energy Facility	))))	ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

BY THE CHAIRMAN: On February 7, 2013, Virginia Electric and Power Company, d/b/a Dominion North Carolina (Dominion), filed a registration statement pursuant to Commission Rule R8-66 for a new renewable energy facility to be located in St. Paul, Virginia. Dominion stated that its 686-MW Virginia City Hybrid Energy Center (VCHEC) will utilize a combination of mine coal, coal waste and biomass (woody biomass, primarily wood chips or green sawdust) to generate electricity. Dominion stated that the facility became operational on July 10, 2012. Dominion stated that it will participate in the PJM GATS tracking system.

The filing included certified attestations that: 1) the facility would be in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facility will be operated as a new renewable energy facility; 3) Dominion will not remarket or otherwise resell any RECs sold to an electric power supplier to comply with G.S. 62-133.8; and 4) Dominion 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 25, 2014, the Public Staff filed the recommendation required by Commission Rule R8-66(e) stating that Dominion's registration statement as a new renewable energy facility should be considered to be complete. The Public Staff further stated that it had reviewed Dominion's methodology to calculate the energy production associated with each fuel type at the VCHEC facility. 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 registration statement, the Chairman finds good cause to accept registration of Dominion's VCHEC facility as a new renewable energy facility. Pursuant to Commission Rule R8-67(d)(2), because Dominion is using multiple fuels to generate electricity, the facility shall earn RECs based only upon the energy derived from the renewable energy resources in proportion to the relative energy content of the fuels used. Dominion shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. To the extent that Dominion is not otherwise participating in a REC tracking system, it will be required to participate in the NC-RETS REC tracking system (www.ncrets.org) in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration by Dominion for its VCHEC facility to be located in St. Paul, Virginia as a new renewable energy facility shall be, and is hereby, accepted.

2. That Dominion 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 _10th_ day of April, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-2, SUB 238

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by Carolina Power and	)	ORDER APPROVING MODIFICATION
Light Company for Approval of Meter	)	OF SAMPLE TEST PLAN
Testing Procedures	)	

BY THE COMMISSION: On December 20, 2013, Duke Energy Progress, Inc. (DEP or the Company), filed a letter requesting approval of modifications to its sample test plan pursuant to Commission Rule R8-13, "Periodic tests of meters," to include three-phase self-contained demand meters.

In an Order issued December 20, 1989, in this docket, the Commission approved the request of Carolina Power & Light Company (now DEP) to use statistical sampling for its three-phase self-contained non-demand meters. The Company maintains that the replacement of the mechanical registers and assemblies with an electronic processor allows for statistical sampling of its three-phase self-contained demand meters. As such, there is no need to treat these demand meters differently from non-demand meters.

Attached to the letter is a copy of American National Standards Institute (ANSI) Cl2.1 section 5.2 and letters from meter manufacturers (Itron, Elster, and Ladis and Gyr) supporting the requested three-phase self-contained demand meter testing modification. DEP states that this meter testing methodology has also been adopted by Florida Power and Light, Georgia Power, and Oklahoma Gas and Electric.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on February 3, 2014. The Public Staff indicated that it had reviewed the Company's filing and had discussed the proposed changes with metering experts of other utilities and a member of the ANSI C12.1 committee on meters. The Public Staff stated that it believes the Company's requested modification is reasonable and recommended that it be approved.

Based on the foregoing, and the recommendation of the Public Staff, the Commission concludes that the proposed modification of DEP's sample test plan should be approved.

IT IS, THEREFORE, ORDERED that DEP is allowed to modify its sample test plan to include three-phase self-contained demand meters.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of February, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-22, SUB 507

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric and Power Company d/b/a Dominion North Carolina Power for Approval of Non-residential Heating and Cooling Efficiency Program	))))	ORDER APPROVING PROGRAM

BY THE COMMISSION: On June 30, 2014, Virginia Electric and Power Company (VEPCO), d/b/a Dominion North Carolina Power (DNCP), filed an application in the above-captioned docket to implement its Non-residential Heating and Cooling Efficiency Program (Program) as a new energy efficiency (EE) program under G.S. 62-133.9 and Commission Rule R8-68.

As proposed, the Program would provide non-residential[1] customers a one-time incentive to encourage the installation of a variety of high efficiency heating, ventilation, and air conditioning (HVAC) systems and equipment measures for new installations and to upgrade existing installations. Such measures would include air conditioner upgrade; heat pump upgrade; chiller upgrade; economizer; and variable frequency drive. The prescriptive incentives would be paid on a dollar ($) per ton, horsepower, or unit basis, depending on the equipment installed. As modeled, the Program would pay each participant an average one-time incentive of $1,653. The incentive would vary depending on the HVAC equipment and the associated energy savings resulting from each installation.

If approved, DNCP would market the Program through a network of contractors. DNCP via its third party Program implementation vendor has developed a website, www.dom-nc-vendor.com, for contractors to enroll. DNCP's third party Program implementation vendor would also hold orientation sessions to enroll contractors in the network and provide them with information on how customers can participate in the Program, as well as information concerning the Program's benefits and incentives.

DNCP stated, among other things, that the Program would be cost-effective and would serve the public interest. Therefore, DNCP requested that the Commission:

1. Approve the Program for implementation on and after January 1, 2015;

2. Find that the Program meets the requirements of a new demand-side management (DSM) or EE program consistent with Commission Rule R8-69;

3. Find that all costs incurred by DNCP associated with the Program should be eligible for consideration for cost recovery through DNCP's annual DSM/EE rider to be filed in accordance with Commission Rule R8-69; and

[1] Includes customers in the Commercial, Public Authority (i.e., governmental), and Industrial classes.

4. Approve the proposed utility incentives for inclusion in DNCP's annual DSM/EE rider in accordance with Commission Rule R8-69, and the Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), previously agreed upon by DNCP and the Public Staff and approved by the Commission on October 14, 2011, in Docket No. E-22, Sub 464.

On July 25, 2014, the Public Staff – North Carolina Utilities Commission (Public Staff), filed a motion to extend the time for the filing of its comments on DNCP's application. By Order dated July 28, 2014, the Commission extended the deadline for filing comments, protests, or responses to DNCP's application to August 29, 2014.

On September 16, 2014, the Public Staff filed a second motion to extend the time for the filing of comments on DNCP's application. By Order dated September 17, 2014, the Commission extended the deadline for filing comments, protests, or responses to DNCP's application to September 23, 2014.

On September 23, 2014, the Public Staff filed its comments on DNCP's application for approval of the Program. The Public Staff noted that the proposed Program is generally the same as that proposed in Virginia by VEPCO, d/b/a Dominion Virginia Power (DVP), which was approved by the Virginia State Corporation Commission (VSCC) in Docket No. PUE-2013-00072 on April 29, 2014. The Public Staff opined that it is more cost-effective to implement a program across both VEPCO jurisdictions than to implement a program in just one jurisdiction. The proposed Program would replace the North Carolina-only Commercial HVAC Upgrade Program that was terminated at the request of DNCP by Order dated August 13, 2014, in Docket No. E-22, Sub 467.[1]

The Public Staff stated that it had reviewed DNCP's filing and DNCP's responses to Public Staff data requests, and had discussed the applications and responses to data requests with representatives of DNCP. In addition, the Public Staff stated the application is consistent with the confidential version of a report prepared by ICF International (ICF Report), dated October 8, 2013, other confidential manufacturer information provided by DNCP, and DNCP's 2014 Integrated Resource Plan (IRP), filed on August 29, 2014, in Docket No. E-100, Sub 141. Further, the Public Staff stated that the application complies with the requirements of Commission Rule R8-68, as well as the requirements of the Mechanism.

With regard to the ICF Report, the Public Staff stated that DNCP based its design and evaluation of the potential of the Program on data derived from the ICF Report. ICF's methodology involved developing estimates of market potential, net-to-gross inputs, costs, benefits, and energy and capacity savings assuming measure lives appropriate for the Program. The Public Staff reviewed the ICF Report and believes it to be reasonable for purposes of designing and modeling the programs.

Commission Rule R8-68(c)(2)(iv) provides that the electric public utility filing for approval of a DSM or EE measure must provide economic justification for each proposed measure

[1] The North Carolina-only Commercial HVAC Upgrade Program was closed to new participants effective September 30, 2014, allowing DNCP until December 31, 2014, to process pending applications.

or program, including the results of at least four cost-effectiveness tests: the Total Resource Cost test (TRC), the Participant test, the Utility Cost test (UCT), and the Ratepayer Impact Measure test (RIM). DNCP provided its calculations of the Program's cost-effectiveness in Figures 9 (with utility incentives) and 9A (without utility incentives) of its application.

The Public Staff stated that it has reviewed both the inputs and the results of the cost-effectiveness tests submitted by DNCP and noted a typographical error in the NPV costs used in Figure 9A. On October 15, 2014, DNCP filed an updated Page 14 of 21 of its application to correct the inadvertent transposition of utility cost test values presented in Figure 9A of the application. The Public Staff further noted that the avoided costs used to determine the cost-effectiveness of DNCP's proposed EE programs are consistent with those reflected in DNCP's 2013 IRP. The Public Staff commented that, as shown in Figures 9 and 9A (corrected) of the application, the cost-effectiveness tests indicate that the Program should be cost-effective under the UCT, the TRC, and the Participant test (Figure 9 only), but not the RIM. Thus, on the whole, such calculations indicate that the Program should be cost-effective.

With regard to evaluation, measurement, and verification (EM&V), the Public Staff noted that DNCP would continue to use a third-party EM&V consultant to implement its EM&V plan for the Program. DNCP indicated in its application that it plans to file its EM&V protocols for the Program with its annual EM&V report that would be filed in the spring of 2015. The Public Staff further noted that DNCP included a basic outline of the industry-accepted methods and protocols the EM&V consultant would use to assess the performance of the Program. These methods and protocols are intended to assess the incremental and cumulative participation, savings, costs, and net-to-gross factors associated with the Program consistent with DNCP's previous EM&V reports. This data would be used to verify program performance and provide the basis for any true-up of program savings and costs. The Public Staff has reviewed this outline and believes it is reasonable.

In addition, with respect to Commission Rule R8-68(c)(2)(vi) the Public Staff stated that it has not discovered any information suggesting that the Program would affect a customer's decision to install natural gas versus electric service. Further, pursuant to Commission Rule R8-68(c)(2)(vii), DNCP listed the Program in its 2014 IRP as a new EE program and included peak demand and energy savings from the Program in its forecast.

With respect to the proposed tariff for the Program, the Public Staff recommended that DNCP amend the "Availability" section of the tariff to indicate that the Program is available to customers who either own or lease their facilities, and that customers who lease their facilities be required to secure the permission of the landlord prior to participation in the Program.

The Public Staff recommended that the Program be approved as a new EE program pursuant to Commission Rule R8-68 and that DNCP be required to file a compliance tariff for the Program consistent with the Public Staff's recommendation. No other party intervened or filed comments in this proceeding.

On October 15, 2014, DNCP filed an updated tariff incorporating language in the "Availability" section of the tariff, as recommended by the Public Staff, clarifying DNCP's intent that the Program would be available to customers who lease as well as own eligible facilities.

Based on the foregoing and the entire record in this proceeding, the Commission finds good cause to approve the Non-residential Heating and Cooling Efficiency Program as a new EE program. The Commission finds and concludes that the Program is in the public interest, has the potential to encourage EE, is consistent with DNCP's IRP, and meets the requirements specified in Commission Rule R8-68.

The Commission finds and concludes that the amended Program tariff filed by DNCP on October 15, 2014, which reflects the change recommended by the Public Staff, is reasonable and appropriate.

Further, the Commission concludes that the appropriate ratemaking treatment for the Program, including program costs and incentives, should be determined in DNCP's annual cost recovery rider approved pursuant to Commission Rule R8-69.

IT IS, THEREFORE, ORDERED as follows:

1. That the Non-residential Heating and Cooling Efficiency Program shall be, and is hereby, approved as a new EE program pursuant to Commission Rule R8-68.

2. That the Commission shall determine the appropriate ratemaking treatment for the Non-residential Heating and Cooling Efficiency Program, including program costs and incentives, in DNCP's annual cost recovery rider, in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission's Order Approving Agreement and Stipulation of Settlement, Approving DSM/EE Rider, and Requiring Compliance Filing issued on October 14, 2011, in Docket No. E-22, Sub 464.

3. That DNCP's updated tariff (Schedule NRHCE) filed on October 15, 2014, which reflects the change recommended by the Public Staff, shall be, and is hereby, approved effective for service rendered on and after January 1, 2015.

ISSUED BY ORDER OF THE COMMISSION.
This the _27th_ day of October, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner James G. Patterson did not participate.

DOCKET NO. E-7, SUB 1052

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67	))))))	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2013 REPS COMPLIANCE

HEARD: Tuesday, June 3, 2014, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

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

Charles A. Castle, Associate General Counsel, Duke Energy Carolinas, LLC, 550 South Tryon Street, DEC 45A, Charlotte, North Carolina 28201

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, L.L.P., 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the North Carolina Sustainable Energy Association:

Michael D. Youth, 111 Haynes Street, Raleigh, North Carolina, 27604

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center Raleigh, North Carolina 27699

BY THE COMMISSION: On March 5, 2014, Duke Energy Carolinas, LLC (DEC or the Company), filed its Application for Approval of REPS Cost Recovery Rider and 2013 REPS Compliance Report, seeking an adjustment to its North Carolina rates and charges pursuant to G.S. 62-133.8(h) and Commission Rule R8-67. This statute and rule require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of incremental costs incurred to comply with the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(b), (d), (e) and (f), and to true-up any under-recovery or over-recovery of compliance costs. DEC's application was accompanied by the pre-filed testimony and exhibits of Jonathan L. Byrd, Renewable Strategy and Compliance Manager for DEC, and Veronica I. Williams, Rates and Regulatory Strategy Manager for DEC. In its application and pre-filed testimony, DEC sought approval of a proposed REPS rider that incorporated the Company's proposed adjustments to its North Carolina retail rates. One of the exhibits to witness Byrd's testimony was Duke's 2013 REPS compliance report, which is required to be filed annually under Rule R8-67(c).

On March 19, 2014, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. The Order set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEC's rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc., and the North Carolina Sustainable Energy Association (NCSEA). Each of these petitions to intervene was allowed by the Commission. The intervention and participation of the Public Staff are recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 19, 2014, the Public Staff filed a Motion for Extension of Time requesting that all intervenors be granted one additional day, until May 20, 2014, to file testimony. The Commission approved the time extension. On May 20, 2014, DEC filed the supplemental testimony of witnesses Byrd and Williams. On the same day, the Public Staff filed the testimony and exhibit of Kennie D. Ellis, Engineer, Electric Division, and the affidavit of Catherine L. Eastwood, Staff Accountant, Accounting Division.

On May 21, 2014, DEC filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's March 19, 2014 Order.

On May 29, 2014, DEC filed the rebuttal testimony of witness Byrd.

The matter came on for hearing on June 3, 2014. No public witnesses appeared at the hearing. DEC presented the testimony and exhibits of witnesses Byrd and Williams, who testified as a panel, and the Public Staff presented the testimony and exhibits of witness Ellis and the affidavit of Catherine L. Eastwood.

Based upon the foregoing, the testimony and exhibits introduced at the hearing, DEC's records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. DEC is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. DEC is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in North Carolina. DEC is also an electric power supplier as defined in G.S. 62-133.8(a)(3). DEC is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. Under the State's REPS, G.S. 62-133.8, in 2013 electric power suppliers were required to meet 3 percent of their previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency (EE) measures. Electric power suppliers were required to acquire solar energy, or renewable energy certificates (RECs) for solar power, in an amount equal to at least 0.07 percent of the previous year's North Carolina retail sales. The sources can be a combination of new solar electric facilities and new metered solar thermal energy facilities. The electric power suppliers of North Carolina were initially required by G.S. 62-133.8, and then by the Commission's November 29, 2012 Order in Docket No. E-100, Sub 113, to procure a certain portion of their renewable energy requirements in 2013 from electricity generated by poultry and swine waste. However, in the Commission's Notice of Decision and Order dated December 20, 2013, in Docket No. E-100, Sub 113[1], these requirements were deferred until 2014.

3. G.S. 62-133.8(h)(4) provides that an electric power supplier shall be allowed to recover through an annual rider the incremental costs incurred to comply with the REPS.

4. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled RECs constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

5. DEC has agreed to provide REPS compliance services, including the procurement of RECs, to the following electric power suppliers pursuant to G.S. 62-133.8(c)(2)(e): Blue Ridge Electric Membership Corporation (EMC), the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the Town of Kings Mountain, and Rutherford EMC.

6. DEC and the seven electric power suppliers for which DEC is providing compliance services met their 2013 REPS obligations, except for those from which they had been relieved under the Commission's Notice of Decision and Order of December 20, 2013, in Docket No. E-100, Sub 113. Therefore, DEC's 2013 REPS compliance report should be approved.

7. DEC projects that it will not meet its 2014 swine waste resource requirement and intends to petition the Commission to change its 2014 swine waste resource obligation. DEC should file such petition as soon as possible.

[1] The final order was issued March 26, 2014.

8. For purposes of DEC's annual rider pursuant to G.S. 62-133.8(h), the test period and billing period for this proceeding are, respectively, the calendar year 2013 and the 12-month period ending August 31, 2015.

9. The research activities funded by DEC during the test period and planned for the billing period are renewable research costs recoverable under G.S. 62-133.8(h)(1)(b). These research costs are within the statute's $1-million annual limit.

10. The REC sales addressed in this proceeding were in the public interest. DEC accounted for the sales appropriately.

11. Under the Commission's Order of March 31, 2009, in Docket No. E-100, Sub 83, when a customer chooses to take retail electric service under a net metering rate schedule, other than a time-of-use (TOU) schedule, the RECs associated with the customer's electric generation belong to the utility. Pursuant to this Order, DEC has the legal right to claim ownership of a growing number of RECs produced by customer-owned generating facilities. However, it has not taken steps to have the facilities registered with the Commission so that the energy output can count toward RECs issued via NC-RETS. DEC should estimate the number of RECs that it would be able to obtain from these facilities and proceed to request a waiver in lieu of registering the facilities, unless the administrative costs of doing so would outweigh the benefits of securing these additional RECs.

12. In some of its REC purchase contracts, DEC has required its REC suppliers to provide environmental attributes that are not included in the statutory definition of a REC in G.S.62-133.8(a)(6). These contract provisions are not prohibited. However, costs associated with DEC's purchase of environmental attributes included in RECs could be disallowed in future cost recovery proceedings upon a finding that such recovery from DEC's North Carolina retail customers is not appropriate.

13. For purposes of establishing the REPS Experience Modification Factor (EMF) rider in this proceeding, DEC's incremental costs of REPS compliance during the test period were $11,242,746, of which $10,410,734 is appropriately recovered from DEC's retail customers. These costs are reasonable and were prudently incurred.

14. DEC's North Carolina retail test period REPS expense over-collections were $785,369, $1,967,802, and $277,106 for the residential, general service, and industrial customer classes, respectively, excluding interest and the regulatory fee.

15. DEC's projected incremental costs for the billing period are $16,053,813, of which $14,793,430 is appropriately recovered from DEC's retail customers. DEC's North Carolina retail prospective billing period expenses for use in this proceeding are $8,546,797, $5,619,748, and $626,885 for the residential, general service, and industrial customer classes, respectively, excluding the regulatory fee.

16. The appropriate monthly amounts of the REPS EMF rider per customer account, including interest but excluding the regulatory fee, to be collected during the billing period are ($0.05) for residential accounts, ($0.84) for general service accounts, and ($5.45) for industrial accounts.

17. The appropriate monthly amounts of the REPS rider per customer account, excluding the regulatory fee, to be collected during the billing period are $0.44 for residential accounts, $2.06 for general service accounts, and $10.56 for industrial accounts.

18. The combined monthly REPS and REPS EMF rider charges per customer account, including both interest and the regulatory fee, to be collected during the billing period are $0.39 for residential accounts, $1.22 for general service accounts, and $5.11 for industrial accounts.

19. DEC's REPS incremental cost rider to be charged to each customer account for the billing period is within the annual cost caps established in G.S. 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are not contested.

G.S. 62-133.8(b)(1) and (c)(1) establish a REPS requirement for all electric power suppliers in the State. These provisions require each electric power supplier to provide a certain percentage of its North Carolina retail sales from various renewable energy or EE resources. Authorized methods of compliance with the REPS requirement for electric public utilities are listed in G.S. 62-133.8(b)(2) as follows:

(a) Generate electric power at a new renewable energy facility.
(b) Use a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel.
(c) Reduce energy consumption through the implementation of an energy efficiency measure . . . .
(d) Purchase electric power from a new renewable energy facility . . . .
(e) Purchase renewable energy certificates derived from in-State or out-of-state new renewable energy facilities. . . .
(f) Use electric power that is supplied by a new renewable energy facility or saved due to the implementation of an energy efficiency measure that exceeds the requirements of this section for any calendar year as a credit towards the requirements of this section in the following calendar year.
(g) Electricity demand reduction.

Each of these measures is subject to certain additional limitations and conditions. G.S. 62-133.8(c) has similar requirements for electric membership corporations and municipal electric systems. In 2013, the electric public utilities were required generally to meet 3 percent of their previous year's North Carolina retail electric sales by a combination of the measures authorized by G.S. 62-133.8(b).

G.S. 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources is 0.07 percent for 2012-14.

G.S. 62-133.8(e) requires a certain percentage of the total electric power sold to retail electric customers in the State to be supplied, or contracted for supply each year, by swine waste. In 2013, the aggregate requirement for swine waste resources was 0.07 percent. G.S. 62-133.8(f) requires a specific amount of electric power sold to retail electric customers in the State to be supplied, or contracted for supply each year, by poultry waste resources. In 2013, the aggregate requirement for poultry waste resources was 170,000 megawatt-hours (MWh). Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification, issued on March 31, 2010, in Docket No. E-100, Sub 113, DEC's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour (kWh) sales from the previous year divided by the previous year's total North Carolina retail kWh sales for all electric power suppliers. However, in its Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief, issued on November 29, 2012 in Docket No. E-100, Sub 113, and its Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief, issued on March 26, 2014 in the same docket, the Commission found that because of the immaturity of the technology of power production from swine and poultry waste, and for a variety of other reasons, most of the State's electric power suppliers would be unable to comply with the swine and poultry waste set-aside requirements for 2012 and 2013, despite having made a reasonable effort to comply. The Commission's Orders in these cases directed, pursuant to G.S. 62-133.8(i)(2), that the swine waste set-aside requirement for 2012 be eliminated, that the 2013 swine waste requirement be delayed for a year, and that the poultry waste requirements for 2012-14 be delayed for a year. As a result, the statewide swine waste requirement for 2014-15 is 0.07 percent, and the aggregate statewide poultry waste requirement is 170,000 MWh for 2014 and 700,000 MWh for 2015.

G.S. 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with G.S. 62-133.8 through an annual rider. G.S. 62 133.8(h)(1) provides that the term "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to G.S. 62-133.9. The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect."

DEC's 2013 REPS compliance report stated that pursuant to G.S. 62-133.8(c)(2)(e) the Company provided renewable energy resources and compliance reporting services for Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain, and Rutherford EMC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in DEC's 2013 REPS compliance report and in the direct testimony of DEC witness Byrd and the testimony of Public Staff witness Ellis. In addition, the Commission takes judicial notice of information contained in NC-RETS.

DEC's 2013 REPS compliance report was admitted into evidence as Byrd Exhibit No. 1. This report provides the information required by Commission Rule R8-67(c) in aggregate for DEC and the wholesale customers for which DEC has agreed to provide REPS compliance services. Public Staff witness Ellis testified that he had reviewed the compliance report and recommended that it be approved.

DEC's 2013 REPS compliance report stated that its combined 2012 retail electric sales for itself and the seven wholesale customers for which it provided compliance services amounted to 57,925,034 MWh; hence, the related 2013 REPS obligations amounted to 1,737,752 RECs (3 percent of 57,925,034), including 40,548 solar RECs (0.07 percent of 57,925,034). Public Staff witness Ellis testified that these numbers of RECs satisfied the REPS requirements that 3 percent of 2012 retail sales must be matched with an equivalent number of RECs in 2013, including 0.07 percent of 2012 retail sales that must be matched with an equivalent number of RECs derived from solar energy. Witness Ellis noted that in addition to the RECs required for compliance with the solar set-aside, DEC also used 10,916 solar RECs to meet the general requirement.

According to the records in NC-RETS, DEC correctly transferred a total of 1,737,757 RECs[1] into the NC-RETS compliance sub-accounts, with one of these sub-accounts earmarked toward its own 2013 obligation and the others toward the seven wholesale customers' obligations; among these 1,737,757 RECs were 51,464 solar RECs, including the 10,916 solar RECs used for general compliance. This is consistent with the information in DEC's compliance report. NC-RETS further indicates that DEC complied with the provisions of G.S. 62-133.8(b)(2)(e) and (c)(2)(d) that out-of-state RECs may not be used to meet more than 25 percent of an electric power supplier's REPS requirements. No parties disputed that DEC and the wholesale customers complied with their 2013 REPS requirements, and witnesses Byrd and Ellis both stated that DEC and the seven wholesale customers met the 2013 REPS requirements.

[1] As noted in the testimony of witness Ellis, DEC placed 1,737,757 RECs in its compliance sub-account and those of its wholesale customers, rather than 1,737,752, because its use of several sources of RECs frequently requires rounding up to the next whole REC. The Commission understands that because any given electric power supplier must comply via a given number of "whole" RECs (a fraction of a REC is not permitted), an aggregated group of power suppliers will seemingly "over-comply" by several RECs.

Therefore, the Commission finds and concludes that DEC and the seven wholesale customers for which it is providing REPS compliance services have complied with the REPS requirements for 2013, and that DEC's 2013 REPS compliance report should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the testimony of DEC witness Byrd. Witness Byrd testified that DEC projected that it would not meet its swine waste resource obligations in 2014. He testified that the Company would petition the Commission for a modification of its 2014 obligations after attending a stakeholder meeting to be hosted by the Public Staff. During the hearing it was noted that because the utilities in 2013 did not file a similar modification request until mid-September, the Commission was not able to issue its final Order in that proceeding until March of 2014. Therefore, DEC is strongly encouraged to request any modification that it thinks necessary and appropriate as soon as possible.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controversial.

Commission Rule R8-67(e)(3) provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its fuel charge adjustment proceedings, which is specified in Rule R8-55(c) for DEC to be the calendar year. Therefore, DEC proposed that the test period for its REPS cost recovery proceeding be the calendar year 2013.

Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period that "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel proceeding, Docket No. E-7, Sub 1051, and in this proceeding, DEC has proposed that its rate adjustments take effect on September 1, 2014, and remain in effect for a 12-month period. This period is the "billing period."

The test period and billing period proposed by DEC were not challenged by any party. Therefore, the Commission finds that the test period and billing period appropriate for this proceeding are the calendar year 2013 and the twelve months ending August 31, 2015, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact appears in the direct testimony and exhibits of DEC witnesses Byrd and Williams, and the affidavit of Public Staff witness Eastwood.

Pursuant to G.S. 62-133.8(h)(1), "incremental costs" include, among other things, "all reasonable and prudent costs incurred by an electric power supplier to . . . (b) (f)und research that encourages the development of renewable energy, energy efficiency, or improved air quality, provided those costs do not exceed one million dollars ($1,000,000) per year." Whether specific test period expenditures to fund research are eligible for cost recovery through an annual rider pursuant to this provision is a matter to be determined by the Commission on a case-by-case basis.

DEC witness Byrd testified that DEC's research efforts are an integral part of its REPS compliance effort, and they have funded the following projects:

(1) A study, conducted with Duke University, of the potential in North Carolina for injection of swine biogas into interstate pipelines with subsequent centralized generation and production of swine waste RECs, as compared with individual on-site swine waste-to-energy projects. The final results of the study have been published and are available to the public.

(2) Continued operation, in partnership with Duke University, of the Loyd Ray Farms swine waste-to-energy project. A summary of the project's progress was provided as an exhibit to witness Byrd's testimony.

(3) A study, conducted by the Company in partnership with Pacific Northwest National Laboratory and Clean Power Research, addressing the ancillary services impact of solar generation at the system level based on granular solar photovoltaic (PV) forecasts in the Company's service territory. Efforts are ongoing and results are expected during 2014.

(4) A study, conducted by the Company in partnership with the University of North Carolina at Charlotte, of one potential solution for addressing the current declining Eastern Interconnection frequency response performance as additional degradation is expected with increasing levels of intermittent resources. A final report from the University of North Carolina at Charlotte was provided as an exhibit to witness Byrd's testimony.

(5) An ongoing study, conducted by the University of North Carolina at Chapel Hill, of offshore wind resources outside the coastal barrier islands. Witness Byrd testified that field data collection, modeling, and analysis is ongoing.

(6) An ongoing closed-loop biomass research project to study the yield potential for various woody and herbaceous crops, managed by American Forest Management. An update on this project was provided as an exhibit to witness Byrd's testimony.

(7) A forum sponsored by the Rocky Mountain Institute, organized to overcome barriers to economic deployment of distributed energy resources in the United States electric sector. Reports and findings are not presently available.

(8) Various programs, conducted by the Electric Power Research Institute, to which DEC subscribes. The study results are proprietary and are available to the public for a fee.

(9) Renewable energy news reports and market analyses, obtained by the Company from Bloomberg New Energy Finance, HIS Global, Megawatt Daily, SolarBuzz, and Photon Consulting, and available to the public for a fee.

In its Order in DEC's last REPS rider proceeding, Docket No. E-7, Sub 1034, the Commission directed that DEC shall file in all future REPS rider applications the results of studies the costs of which were recovered via its REPS EMF and REPS rider, including the overall program number and specific project number for each project sponsored by EPRI; and, for those studies that are subject to confidentiality agreements, information (including an internet or mailing address) regarding how parties can access the results of those studies. DEC has complied with this requirement and has not objected to its being applied to future cases, and the Commission believes that the requirement should remain in effect.

The amount of DEC's research expenses was provided in witness Williams' confidential exhibits and is below the statutory limit of $1 million per year. In her affidavit, Public Staff witness Eastwood stated that the Public Staff's investigative procedures in this proceeding included a review of certain expenditures, including DEC's research costs.

Neither the Public Staff nor any other intervenor took issue with DEC's testimony concerning the nature and costs of its research activities. Accordingly, the Commission concludes that these costs are reasonable and may be recovered through the REPS and REPS EMF riders.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the testimony of DEC witness Byrd and the affidavit of Public Staff witness Eastwood.

Public Staff witness Eastwood stated in her affidavit that the Public Staff had reviewed information provided by DEC related to gains on the sales of RECs that DEC recorded during the EMF period. She stated further that the Public Staff is satisfied that DEC's treatment of these gains is consistent with the Commission's May 13, 2014 Order Regarding Accounting Treatment for REC Sales[1] in Docket No. E-100, Sub 113.

DEC witness Byrd testified that DEC had purchased out-of-state wind RECs several years ago, and that the market price of those RECs had since increased. He stated that DEC was able to sell those RECs and purchase replacement RECs at a much lower price. He stated that "we netted a substantial amount of proceeds for our customers." Witness Byrd's testimony is consistent with the data shown on page 3 of his confidential revised exhibit 2.

Based on the affidavit of Public Staff witness Eastwood, witness Byrd's confidential revised exhibit 2 and his testimony, the Commission finds that DEC's REC sales were in the public interest and were properly accounted for, with net proceeds being credited to customers in the calculation of the EMF rider.

[1] This Order stated that the "Commission will review REC sales on a case-by-case basis in REPS rider proceedings and general rate cases, as the issues arise. The electric public utility will have the burden of proving that each REC sale was in the best interest of its customers and should file complete information regarding the original purchase price, resale price, the cost of replacement RECs and any incremental administrative or brokerage fees incurred pursuant to the transaction."

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is found in the testimony of Public Staff witness Ellis.

Witness Ellis testified that in its order of March 31, 2009, in Docket No. E-100, Sub 83, the Commission stated:

> If the customer chooses to take retail electric service pursuant to a TOU-demand rate schedule, it shall retain ownership of all RECs associated with its electric generation. If the customer chooses to take retail electric service pursuant to any other rate schedule, RECs associated with all electric generation by the facility shall be assigned to the utility as part of the net metering arrangement.

According to witness Ellis, no mechanism currently exists to facilitate the assignment or transfer of RECs produced by non-TOU net-metering customers to the utility. The number of net-metered solar PV facilities has increased considerably in the past two years and is expected to continue to increase in future years, resulting in a larger number of RECs being generated and potentially available to DEC for REPS compliance purposes. Witness Ellis stated that DEC and the Public Staff have discussed the potential development of a waiver to exempt non-TOU solar PV net-metered customers from the registration requirements of Commission Rule R8-66, instead allowing DEC to make an annual blanket filing that provides an estimate of MWh from all of the applicable facilities in order to claim the RECs from these customers. This approach would be similar to the one approved for use by Duke Energy Progress, Inc.'s residential SunSense solar rebate program in Docket No. E-2, Sub 979. Witness Ellis stated that DEC had indicated to the Public Staff that it is developing such a waiver.

Witness Ellis testified that the Public Staff supports DEC's efforts to properly register its non-TOU net-metered customers' solar PV facilities and use their RECs for REPS compliance purposes. He recommended that DEC seek approval of the waiver in a timely fashion, so as to account for the eligible RECs earned by these systems over the past two years. DEC did not cross-examine witness Ellis on this matter at the hearing or take issue with his recommendation.

The Commission notes that these net-metering RECs are cost-free from DEC's perspective, and thus they might serve to reduce DEC's annual REPS charges to customers in the future. Therefore, the Commission will require DEC to evaluate whether the benefits of securing these RECs outweigh the administrative costs that would be incurred. DEC should estimate the number of net-metering RECs that it would be able to obtain and compare the administrative cost involved in order to determine whether accounting for the net-metering RECs in this manner is cost-effective. If so, DEC should petition the Commission for a blanket waiver of the registration requirements in Rule R8-66.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact appears in the direct testimony of Public Staff witness Ellis and the rebuttal testimony of DEC witness Byrd.

Public Staff witness Ellis testified that through discovery the Public Staff obtained a copy of the standard form contract that DEC uses to purchase RECs. This contract, which was received into evidence as Ellis Confidential Exhibit 1,[1] requires the seller to grant DEC broader environmental attributes than are provided for in the statutory definition of a REC in G.S. 62-133.8(a)(6). The statute provides:

> "Renewable energy certificate" means a tradable instrument that is equal to one megawatt hour of electricity or equivalent energy supplied by a renewable energy facility, new renewable energy facility, or reduced by implementation of an energy efficiency measure that is used to track and verify compliance with the requirements of this section as determined by the Commission. A "renewable energy certificate" does not include the related emission reductions, including, but not limited to, reductions of sulfur dioxide, oxides of nitrogen, mercury, or carbon dioxide.

Witness Ellis testified that by excluding “related emission reductions” from the definition of a “renewable energy certificate,” the General Assembly specifically allowed a REC seller to retain these environmental attributes, as distinguished from the attributes associated with the use of renewable fuels, and market them separately if it can find a buyer willing to purchase them.

DEC witness Byrd testified that the language of DEC’s Ellis Confidential Exhibit 1, and other contracts between DEC and REC sellers, is consistent with G.S. 62-133.8(a)(6) and is designed to protect DEC against double counting of RECs, that is, the sale of the same REC to more than one purchaser. According to witness Byrd, prevention of double counting is in the interest of both DEC and its ratepayers, because the suspicion of double counting tends to reduce the value of RECs. He testified that G.S. 62-133.8(i)(3) directs the Commission to adopt rules that prohibit both the double use and the double claiming of RECs. That statute states: “In developing rules, the Commission shall: …”

> Ensure that energy credited toward compliance with the provisions of this section not be credited toward any other purpose, including another renewable energy portfolio standard or voluntary renewable energy purchase program in this State or any other state.

Witness Byrd testified that:

> The utility buyer needs to obtain ownership of all of the attributes associated with the generation of renewable energy to ensure that the energy can be claimed as “renewable,” and this includes the exclusive right to all claims relating to the

[1] Ellis Confidential Exhibit 1 and Public Staff Byrd Cross-Examination Exhibit 4 are identical.

> generation of renewable energy, in order to prevent double counting and to protect rate-payers [sic] who ultimately pay for these purchases.

In its post-hearing Brief, NCSEA stated that it does not challenge any of the REPS costs sought to be recovered by DEC. However, NCSEA advocated that for purposes of clarity the Commission "direct DEC to cease using the term 'REC' in its contracts when it is describing something that is different from a statutorily-defined REC."

Under G.S. 62-133.8(a)(6), a renewable energy certificate

> means a tradable instrument that is equal to one megawatt hour of electricity or equivalent energy supplied by a renewable energy facility, new renewable energy facility, or reduced by implementation of an energy efficiency measure that is used to track and verify compliance with the requirements of this section as determined by the Commission.

Therefore, a given megawatt-hour of electric energy that comes from such sources is eligible for REC issuance, and that REC may be used by a North Carolina electric power supplier for REPS compliance. G.S. 62-133.8(a)(6) also provides that a REC

> does not include the related emission reductions, including, but not limited to, reductions of sulfur dioxide, oxides of nitrogen, mercury, or carbon dioxide.

Thus, under North Carolina law, emission reduction attributes are separate and in addition to the "renewable" attributes that must be represented by a REC in order for the REC to be a valid REPS compliance instrument in North Carolina.

The market for RECs is a competitive, nationwide market. The General Assembly signified its intent for electric suppliers to participate in this market by enacting G.S. 62-133.8(b)(2)e, which allows electric suppliers to use out-of-state "certificates" for 25 percent of their REPS compliance. However, in many states the emission reduction attributes are part of a REC and there is no practical way to separate the emission reduction attributes from the renewable energy attributes. Thus, some of those out-of-state RECs will, of necessity, include emission reduction attributes. Likewise, if North Carolina's electric suppliers are to fully participate in the REC market by selling their RECs, then they need RECs that comply with out-of-state requirements. Thus, to prohibit DEC from purchasing RECs that include emission reduction attributes simply because they are more inclusive than North Carolina's statutory definition could prevent DEC from engaging fully in the competitive market for RECs. As a result, DEC's retail ratepayers could lose the advantages of participation in this market. The Commission is not persuaded that the General Assembly intended to create such a restriction on DEC's participation in the REC market.

In addition, the Commission is of the opinion that it is highly unlikely that the General Assembly intended to mandate what had to be sold or what could not be sold as part and parcel of a REC transaction. Rather, we think it likely that the General Assembly left to negotiating and competitive pricing the decision of the specific attributes a REC seller will offer and the attributes a REC buyer will accept. Those are individual decisions better made by market participants based on their needs and the existing market conditions.

The General Assembly did direct that for the purpose of recovering REPS costs from ratepayers the only attributes to be included are the renewable energy characteristics, not emissions reductions. Therefore, DEC is required to act prudently in choosing what RECs to purchase and to charge its customers no more than the reasonable cost of a statutorily-defined REC. Hence, if there was evidence that DEC paid an additional amount for RECs that include emission reduction attributes, then the Commission could deny recovery of that additional cost. However, no party provided any evidence that there is currently a market for the “separated” emission reduction attributes that are at issue. Further, no party provided any evidence that REC producers are being harmed by the REC contract provisions that are at issue, or that DEC is seeking to recover any costs attributable to the inclusion of emission reduction attributes in the RECs it purchased. In addition, by requiring the inclusion of emission reduction attributes, it is possible that DEC is positioning its customers favorably in the face of future federal regulatory requirements. For these reasons, the Commission at this time will decline to require DEC to change its REC purchase contracts. However, in the future, if it is demonstrated that DEC is incurring additional incremental costs due to contract provisions that cause it to unnecessarily purchase emission reduction attributes, DEC will have the burden of showing that such costs are appropriate for recovery from its North Carolina retail ratepayers.

With regard to NCSEA's position that DEC should be required to cease using the term “REC,” the Commission again notes that RECs are defined differently from one state to another. The Commission believes it would cause confusion, rather than clarification, to restrict DEC to the definition of REC that is found in North Carolina’s REPS law and to require DEC to use other terminology for RECs purchased that include emission reduction attributes.

Finally, the burden was on the Company to prove that the RECs it purchased for REPS compliance meet the minimum requirements of G.S. 62-133.8(a)(6), that the costs of all RECs was prudently incurred, and that the cost of all RECs was reasonable. The Commission concludes that DEC has met its burden in this proceeding.

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

The evidence supporting these findings of fact is found in the direct and supplemental testimony and exhibits of DEC witnesses Byrd and Williams and the affidavit of Public Staff witness Eastwood.

G.S. 62-133.8(h)(1) provides that “incremental costs” means “all reasonable and prudent costs incurred by an electric power supplier” to comply with the REPS requirements “that are in excess of the electric power supplier’s avoided costs other than those costs recovered pursuant to G.S. 62-133.9.” DEC witness Williams testified as to the calculation of DEC’s avoided costs and its incremental costs of compliance with the REPS requirements, based on the incurred and projected costs provided by witness Byrd. She stated that for purchased power agreements with a renewable energy facility, DEC subtracted its avoided cost from the total cost associated with the renewable energy purchase to arrive at the incremental cost for that renewable energy purchase during the period in question. Consistent with Commission Rule R8-67(e)(2), which provides that the cost of an unbundled REC "is an incremental cost and has no avoided cost component," the total costs incurred during the test period for unbundled REC purchases were included in incremental costs, as were the projected costs for unbundled REC purchases discussed by witness Byrd for the billing period.

Witness Williams stated that the EMF component of the proposed REPS rider included expenditures relating to co-firing that are recoverable under G.S. 62-133.8(h)(1)(b). She indicated that the fuel and fuel-related costs of these operations were included in the Company's fuel filing pursuant to Rule R8-55 and G.S. 62-133.2; and she further stated that the revenue requirements for DEC's solar photovoltaic distributed generation (PVDG) program were levelized and then reduced by avoided costs to determine incremental costs.

According to witness Williams, in all cases where DEC determined incremental compliance costs as the excess amount above avoided cost, the Company applied an avoided cost rate in cents per kilowatt-hour (kWh) to the expected kWh of renewable energy for each compliance initiative. DEC's approved avoided cost rates are set forth in Rate Schedule PP-N, Purchased Power Non-Hydroelectric, and Rate Schedule PP-H, Purchased Power Hydroelectric (collectively Schedule PP). For executed purchased power agreements, where the price of the REC and energy are bundled, the Company used annualized combined capacity and energy rates as shown on its Exhibit No. 3, filed in Docket No. E-100, Sub 106, Exhibit No. 3 in Docket No. E-100, Sub 117, Exhibit No. 3 in Docket No. E-100, Sub 127, or Exhibit No. 3 in Docket No. E-100, Sub 136, depending on the effective date of the executed contract. For those purchased power agreements with terms that did not correspond with the durational terms for which rates were established in the applicable avoided cost proceeding (i.e., two-, five-, 10- or 15-year durations), DEC computed avoided cost rates for the particular term of the purchased power agreements using the same inputs and methodology used for the applicable Schedule PP rates. The avoided cost components of energy and REC purchased power agreements effective during the billing period were calculated in the same manner.

Witness Williams testified that for the solar PVDG program, the Company determined the avoided cost using a process similar to that described above for a purchased power agreement with a non-standard duration. The inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Sub 117 were used to determine the annualized combined capacity and energy rates for a 20-year term, corresponding to the expected life of the solar facilities.

DEC witness Byrd stated in his supplemental testimony that one of the exhibits attached to his direct testimony included certain components of the Company's REPS compliance costs that had been listed incorrectly. Thus, he submitted a revised exhibit correcting the errors. Witness Williams, in her supplemental testimony, stated that she had revised her exhibits to reflect the corrected compliance costs and thus produce accurate amounts for DEC's proposed REPS riders.

Using the methodology set out above, witness Williams calculated that DEC's incremental REPS compliance costs for the calendar year 2013, the test period in this case, amounted to \$11,242,746, as shown on page 1, line 8 of Revised Williams Exhibit No. 1. Public Staff witness

Eastwood did not take issue with any aspect of witness Williams' calculation, and neither the Public Staff nor any other intervenor contended that any of these costs were incurred imprudently.

Witness Williams proceeded to explain DEC's allocation of REPS costs between its retail and wholesale customers, and its allocation of EE savings among its retail customer classes for purposes of determining REPS charges. She noted that DEC continues to provide services to native load priority wholesale customers that contract with the Company for REPS compliance services, including delivery of renewable energy resources, compliance planning, and reporting. These customers (collectively referred to as Wholesale) are Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain, and Rutherford EMC. The incremental cost of REPS compliance represents the cost to meet the combined total MWh requirement for native load customers, based on the sum of DEC North Carolina retail sales and the Wholesale customers' North Carolina retail sales. In order to properly allocate incremental costs between DEC and its Wholesale customers, the class allocation methodology was performed using a combined aggregate cost cap as shown in Revised Williams Exhibit No. 2 and Williams Exhibit No. 3 for the EMF period and billing period, respectively. The class allocation methodology combines the number of accounts subject to a REPS charge by customer class for both DEC North Carolina retail accounts and the Wholesale customers' North Carolina retail accounts. In cases where a Wholesale customer has chosen to self-supply a portion of its annual REPS requirement – for example, by using its Southeastern Power Administration allocation to partially meet the requirement as provided in G.S. 62-133.8(c) – or where the Company meets its compliance requirements by reduced energy consumption through implementation of EE measures, the combined total number of accounts on which the cost allocation is based was adjusted on a pro-rata basis to recognize that a portion of the compliance will not be supplied by RECs generated or acquired by DEC as part of the combined total requirements. The adjusted totals by class were multiplied by the per-account cost caps to determine the combined total cost cap dollar amounts by customer class and in total. Each customer class was then allocated its share of the incremental costs based on its pro-rata share of the customer cost cap dollar amounts. The cost allocated to each customer class was then divided by the total adjusted number of accounts within each customer class to arrive at an annual per-account charge. The annual per-account charge for each customer class was multiplied by the Company's North Carolina retail adjusted number of accounts within each customer class and totaled to arrive at the incremental cost to be allocated to DEC's North Carolina retail customers. Thus witness Williams determined that $10,410,734 of its total incremental costs should be allocated to DEC's retail customers.

In allocating EE savings among the customer classes, incremental costs assigned to DEC's North Carolina retail customers were separated into two categories: (a) costs related to the solar, poultry and swine compliance requirements or to research and other incremental costs (set-aside and other incremental costs), and (b) costs related to the general requirement[1] (general incremental costs). This separation was based on the percentage of set-aside and other incremental costs and general incremental costs calculated on Revised Williams Exhibit No. 1.

[1] The overall REPS requirement, net of the three set-asides, is generally referred to as the "general requirement."

Set-aside and other incremental costs were allocated among customer classes based on per-account cost caps. General incremental costs were allocated among customer classes in a manner that gives credit for EE certificates (for which there are no general incremental costs) according to the relative energy reduction contributed by each customer class. As a result, general incremental costs were allocated among customer classes based on each class's pro-rata share of requirements for non-EE general RECs. In the future, should this method result in an allocation of costs to a particular class in excess of the cap limit for that class, the excess over the respective cap for that class will be reallocated proportionally to the remaining classes.

Based on this allocation procedure, witness Williams determined that DEC's test-period incremental REPS compliance costs should be allocated to the three retail customer classes as follows: $3,118,287 to the residential class, $6,427,607 to the general class, and $864,840 to the industrial class. She then compared these costs with the actual REPS revenues received during the test period from the three classes, and she found that DEC's over-collections for the test period were $785,369 for the residential class, $1,967,802 for the general service class, and $277,106 for the industrial class, excluding interest and the regulatory fee and as demonstrated on page 2 of Revised Williams Exhibit No. 2.

Public Staff witness Eastwood recommended in her affidavit that DEC's proposed annual REPS EMF amounts and monthly riders for each customer class, "as revised via the Company's Supplemental Testimony and exhibits, be approved."

Neither the Public Staff nor any other intervenor took issue with witness Williams' calculation of test-period incremental costs, her allocation of these costs among the retail customer classes, or her comparison of the allocated costs with test-period revenues. No party contended that any of DEC's compliance costs were incurred imprudently or were unreasonable. Therefore, the Commission finds and concludes that DEC's incremental costs of REPS compliance during the test period, and the Company's over-collections of REPS expenses for the test period, as calculated by witness Williams, were prudent and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is found in the testimony of DEC witnesses Byrd and Williams.

DEC witness Byrd testified that the Company is well positioned to secure a diverse and balanced portfolio of renewable resources that will qualify for the general REPS requirement during the billing period, together with a diverse and balanced portfolio of solar resources, and it also expects to comply with the poultry waste resource requirement. However, witness Byrd testified that DEC will not meet its swine waste resource requirement in 2014. In his Exhibit No. 2, witness Byrd listed the suppliers from whom DEC expects to purchase renewable energy or RECs during the billing period, together with the amounts DEC expects to pay to these suppliers. Witness Williams adjusted these total payments to remove avoided costs and add research and other incremental costs. She concluded that DEC's incremental REPS compliance costs for the billing period would amount to $16,053,813, of which $14,793,430 is appropriately allocated to DEC's retail customers. This is demonstrated on page 2 of Williams Exhibit No. 1. After excluding costs allocable to wholesale customers, and apportioning the remaining costs among the three retail customer classes, she calculated that DEC’s incremental REPS compliance costs for the billing period should be set at $8,546,797 for the residential class, $5,619,748 for the general service class, and $626,885 for the industrial class, excluding the regulatory fee. This is demonstrated on page 3 of Williams Exhibit No. 3.

No party expressed disagreement with the testimony of witness Byrd or the calculations of witness Williams relating to anticipated costs for the billing period. The Commission therefore finds and concludes that DEC’s projected incremental costs of REPS compliance during the billing period will be as calculated by witness Williams.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-19

The evidence for these findings of fact appears in the testimony and exhibits of DEC witness Williams, and the testimony of Public Staff witness Ellis.

Witness Williams’ Revised Exhibit No. 2, page 3, lines 9-11, shows that she calculated a test-period over-collection of REPS costs amounting to $785,369 for the residential class, $1,967,802 for the general service class, and $277,106 for the industrial class, excluding interest and the regulatory fee. With interest included, but still excluding the regulatory fee, she demonstrated that the over-collections are $916,264 for the residential class, $2,295,769 for the general service class, and $323,290 for the industrial class. As reflected on her Revised Exhibit No. 4, witness Williams calculated proposed monthly REPS EMF charges of ($0.05), ($0.84) and ($5.45) per customer account for residential, general service, and industrial customers, respectively, excluding the regulatory fee.

On Williams Exhibit 3, page 3, lines 9-11, witness Williams calculated projected REPS costs for the billing period in the amount of $8,546,797 for the residential class, $5,619,748 for the general service class, and $626,885 for the industrial class, excluding the regulatory fee. Her proposed monthly REPS riders, as shown on her Revised Exhibit No. 4, again excluding the regulatory fee, were $0.44, $2.06, and $10.56 per customer account for residential, general service, and industrial customers, respectively.

Revised Williams Exhibit No. 4 indicates that the combined monthly amounts of the REPS and REPS EMF riders, including interest and the regulatory fee, per customer account, to be billed during the 2014-15 billing period, are $0.39 for residential accounts, $1.22 for general service accounts, and $5.11 for industrial accounts. Witness Williams further demonstrated on her Revised Williams Exhibit No. 4 that DEC’s proposed annual charges for each customer class are well below the caps established in G.S. 62-133.8(h)(4).

In his testimony, witness Ellis stated that the Public Staff recommended approval of DEC’s proposed REPS rider “as amended in its May 20, 2014 supplemental filing.” Witness Ellis proposed rider billing factors that are consistent with the billing factors that DEC proposed.

Therefore, based on the testimony cited above, the Commission finds and concludes that DEC’s proposed EMF and REPS riders should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2014, and expiring on August 31, 2015;

2. That DEC shall establish a REPS EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2014, and expiring on August 31, 2015;

3. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten (10) days after the date of this Order;

4. That DEC shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket as well as in Docket No. E-7, Sub 1051, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in both dockets;

5. That DEC's 2013 REPS compliance report is hereby approved and the RECs in DEC's 2013 compliance sub-accounts in NC-RETS shall be retired; and

6. That DEC shall estimate the number of RECs that it could obtain via those net-metering customers who are not on a time-of-use rate schedule, and work with the Public Staff to determine whether it would be cost-effective to pursue a waiver of the Commission's registration requirements in order to have the associated RECs issued in NC-RETS.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of August, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioners Susan W. Rabon and Don M. Bailey did not participate in this decision.

DOCKET NO. E-22, SUB 514

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to G.S. 62-133.8 and Commission Rule R8-67	))))))	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2013 REPS COMPLIANCE

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

HEARD: Wednesday, November 12, 2014, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

APPEARANCES:

For Dominion North Carolina Power:

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

For the Using and Consuming Public:

Robert S. Gillam and Tim R. Dodge, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On August 28, 2014, Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP or the Company), filed its Application for Approval of Renewable Energy and Energy Efficiency (REPS) cost recovery riders, Riders RP and RPE (Application), pursuant to Commission Rule R8-67. Through this Application, DNCP also requested Commission approval of the Company's 2014 REPS Compliance Report for calendar year 2013 REPS compliance, filed as Company Exhibit CHM-1 attached to the pre-filed direct testimony of Company witness Chiman H. Muchhala. DNCP's Application requested an annual projected rate period revenue requirement of $1,022,618 to be recovered through updated Rider RP, as well as a REPS EMF revenue requirement of $465,566 to be recovered through Rider RPE. In support of its Application, the Company filed the direct testimony and exhibits of witnesses Muchhala, C. Alan Givens, and Robert C. Rice.

On September 5, 2014, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. Pursuant to this Order, the Commission established deadlines for the filing of petitions to intervene, intervenor testimony and exhibits, and Company rebuttal testimony and exhibits, and scheduled the hearing to be held in this proceeding on November 12, 2014.

The North Carolina Sustainable Energy Association filed a petition to intervene on September 11, 2014, and on September 17, 2014, the Commission issued an Order allowing the intervention.

Intervention and participation in this docket by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On October 29, 2014, the Public Staff filed the affidavits of Jack L. Floyd, Engineer, Public Staff - Electric Division, and Catherine L. Eastwood, Staff Accountant, Public Staff - Accounting Division.

On November 5, 2014, DNCP filed the rebuttal testimony of Chiman H. Muchhala in response to the affidavit of Public Staff witness Floyd.

On November 5, 2014, DNCP also filed an affidavit of publication indicating that the Company had provided notice of hearing in newspapers of general circulation as required by the Commission's September 5, 2014 Order.

On November 7, 2014, the Public Staff and DNCP filed a Joint Motion to Excuse Witnesses, stating that they had reached agreement on all contested issues in this docket and had agreed to waive cross-examination of their respective witnesses. Further, the Joint Motion requested that the Commission excuse the Public Staff and DNCP witnesses from attending the evidentiary hearing on November 12, 2014, and admit the testimony, affidavits and exhibits of those witnesses into evidence at the hearing. Also on November 7, 2014, the Commission issued an Order Granting in Part the Joint Motion to Excuse Witnesses. That Order required only DNCP witness Givens to appear at the hearing.

On November 12, 2014, the Commission held the evidentiary hearing as scheduled. At the hearing, the parties agreed that the application, the pre-filed direct and rebuttal testimony of DNCP witness Muchhala, the pre-filed direct testimony of DNCP witness Rice, and the Public Staff's affidavits should be accepted into the record without objection from any party. DNCP witness Givens appeared and was examined by the Commission, and his pre-filed direct testimony was also accepted into the record. All exhibits attached to those testimonies were received into evidence. No public witnesses appeared at the hearing.

On November 14, 2014, DNCP filed verified responses to questions raised by Commissioner Beatty during the hearing, as directed by the Commission at the hearing.

DNCP and the Public Staff filed a joint proposed order on December 5, 2014.

Based upon DNCP's Application, the testimony and exhibits received into evidence at the hearing, the records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. DNCP is a public utility operating in the State of North Carolina as Dominion North Carolina Power, is engaged in the business of generating, transmitting, distributing, and selling electric power and energy to the public for compensation in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DNCP is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

2. Under the State's REPS, G.S. 62-133.8, in 2013 electric power suppliers were required to meet three percent (3%) of their previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency (EE) measures. In addition, by the end of 2013 electric power suppliers must have acquired solar energy, or renewable energy certificates (RECs) for solar energy, in an amount equal to at least 0.07% of the previous year's North Carolina retail sales. The 0.07% solar energy requirement is part of the 3% total REPS requirement. The solar energy sources can be a combination of new solar electric facilities and new metered solar thermal energy facilities. The electric power suppliers of North Carolina were initially required by G.S. 62-133.8 to procure a certain portion of their renewable energy requirements beginning in 2012 from electricity generated by poultry and swine waste. However, by Orders issued November 29, 2012, March 26, 2014, and November 13, 2014, in Docket No. E-100, Sub 113 (collectively, the "Delay Orders"), the Commission delayed the initial swine waste resource requirement until 2015 and the initial poultry waste resource requirement until 2014.

3. General Statute 62-133.8(h)(4) provides that an electric power supplier shall be allowed to recover through an annual rider the incremental costs incurred to comply with the REPS.

4. Pursuant to G.S. 62-133.8(b)(2)(e), DNCP may use 100% out-of-state RECs to achieve REPS compliance. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled RECs constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

5. DNCP has agreed to provide REPS compliance services, including the procurement of RECs, to the Town of Windsor pursuant to G.S. 62-133.8(c)(2)(e). The Town of Windsor's 2013 REPS compliance status is included in DNCP's 2014 compliance report.

6. Taking into account the Commission's Delay Orders that relieved DNCP and other electric power suppliers of the swine and poultry waste resource requirements, DNCP, on its own behalf and on behalf of the Town of Windsor, has complied with its 2013 REPS obligations. DNCP's 2014 REPS compliance report for compliance year 2013 should be approved.

7. For purposes of DNCP's annual rider pursuant to G.S. 62-133.8(h), the rate period is the 12-month period January 1, 2015, through December 31, 2015, and the test period is the 12-month period July 1, 2013, through June 30, 2014.

8. DNCP's micro-grid research project costs are renewable energy research costs recoverable pursuant to G.S. 62-133.8(h)(1)(b). DNCP's research costs are within the statute's $1,000,000 annual limit. It is appropriate for DNCP to provide the Commission annual updates on the status of its micro-grid research during each year of the three-year demonstration period (2015-2017). DNCP should file these updates with its annual REPS compliance report during these years.

9. DNCP's approach of managing its retail REPS costs separately from the REPS costs for its wholesale customer, the Town of Windsor, is reasonable.

10. For purposes of establishing the REPS EMF rider (RPE) in this proceeding, DNCP's incremental costs of REPS compliance during the REPS test period were $465,566.

11. For purposes of establishing the forecasted REPS rider (RP) in this proceeding, DNCP's incremental costs of REPS compliance projected to be incurred during the rate period are $1,022,618.

12. The appropriate monthly amount of the REPS EMF rider to be collected during the billing period, per customer account, including regulatory fee, is $0.22 for residential accounts, $0.95 for commercial accounts, and $6.39 for industrial accounts.

13. The appropriate monthly amount of the REPS rider to be collected during the billing period, per customer account, including regulatory fee, is $0.47 for residential accounts, $2.09 for commercial accounts, and $14.26 for industrial accounts.

14. The combined monthly REPS and REPS EMF rider charges to be collected during the billing period, per customer account, including regulatory fee, are $0.69 for residential accounts, $3.04 for commercial accounts, and $20.65 for industrial accounts.

15. DNCP's REPS incremental cost riders to be charged to each customer account for the billing period are within the annual cost caps established in G.S. 62-133.8(h)(4).

16. DNCP shall evaluate its EE program projections and provide testimony regarding those projections in its 2015 REPS rider application.

17. DNCP's approach to defining a customer account for purposes of developing the REPS rider is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 5

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are not contested.

General Statute 62-133.8(b)(1) and (c)(1) establish a REPS requirement for all electric power suppliers in the State. These provisions require each electric power supplier to provide a certain percentage of its North Carolina sales from various renewable energy or EE resources.

Authorized methods of compliance with the REPS requirement for electric public utilities are listed in G.S. 62-133.8(b)(2) as follows: (a) generate electric power at a new renewable energy facility; (b) use a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel; (c) reduce energy consumption through the implementation of an EE measure; (d) purchase electric power from a new renewable energy facility; (e) purchase RECs derived from in-State or out-of-state new renewable energy facilities; (f) use electric power that is supplied by a new renewable energy facility or energy saved due to the implementation of an EE measure that exceeds the requirements of this section for any calendar year as a credit towards the requirements of this section in the following calendar year; or (g) electricity demand reduction. In 2013, the electric public utilities were required to meet three percent (3%) of their previous year's North Carolina retail electric sales by a combination of the measures authorized by G.S. 62-133.8(b). Each of these compliance methods is subject to certain additional limitations and conditions. G.S. 62-133.8(c) has similar requirements for electric membership corporations (EMCs) and municipal electric systems.

General Statute 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources is 0.07% for the years 2012 through 2014, increasing thereafter.

General Statute 62-133.8(e) requires a certain percentage of the total electric power sold to retail electric customers in the State to be supplied, or contracted for supply each year, by swine waste resources. The General Assembly established an initial aggregate 0.07% swine waste resource requirement in 2012, increasing thereafter. G.S. 62-133.8(f) requires a specific amount of electric power sold to retail electric customers in the State to be supplied, or contracted for supply each year, by poultry waste resources. The General Assembly established an initial aggregate poultry waste resource requirement of 170,000 megawatt-hours (MWh) in 2012, increasing thereafter. Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification issued on March 31, 2010, in Docket No. E-100, Sub 113, DNCP's share of the aggregate State set-aside requirements for energy from swine and poultry waste resources is based on the ratio of its North Carolina retail kilowatt-hour (kWh) sales from the previous year divided by the previous year's total North Carolina retail kWh sales for all electric power suppliers. However, at the joint request of the State's electric power suppliers, including DNCP, the Commission issued the Delay Orders in Docket No. E-100, Sub 113, pursuant to specific authority provided to the Commission by the General Assembly to modify the REPS requirements under G.S. 62-133.8(i)(2).

Specifically, the Commission's November 29, 2012 Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief directed that the swine waste resource set-aside requirement for 2012 be eliminated and that the poultry waste resource requirements for 2012 and subsequent years be delayed for a year. On March 26, 2014, the Commission issued a Final Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Providing Other Relief, approving another one-year delay for both the swine waste resource and poultry waste resource requirements and requiring certain additional reporting by all electric power suppliers, including DNCP. Most recently, on November 13, 2014, the Commission issued a Final Order Delaying Swine Set-Aside and Providing Other Relief, delaying DNCP's and other electric power suppliers' swine waste resource requirement for one year. Through its March 26 and November 13, 2014 Final Orders, the Commission has established that the initial aggregate statewide poultry waste resource requirement for the State's electric power suppliers, including DNCP, is 170,000 MWh for 2014 (increasing to 700,000 MWh for 2015, and 900,000 MWh for 2016 and each year thereafter) and the initial aggregate swine waste resource requirement is 0.07% in 2015 (increasing in 2017 to 0.14% and again in 2020 to 0.20% for each year thereafter).

General Statute 62-133.8(b)(2)e provides that an electric power supplier shall achieve no more than 25% of its annual REPS compliance obligations using RECs from out-of-state new renewable energy facilities. However, this section specifically exempts any electric public utility with less than 150,000 North Carolina retail jurisdictional customers as of December 31, 2006. The Commission held in its Order on Dominion's Motion for Further Clarification, issued September 22, 2009, in Docket No. E-100, Sub 113, that this exemption applies to DNCP for purposes of both its general REPS obligation and individual set-aside requirements pursuant to G.S. 62-133.8(d)-(f). DNCP may, therefore, achieve 100% of its REPS compliance using RECs generated by out-of-state new renewable energy facilities.

General Statute 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with G.S. 62-133.8 through an annual rider. G.S. 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to G.S. 62-133.9. The term "avoided costs" includes both avoided energy costs and avoided capacity costs. Commission Rule R8-67(e)(2) provides that the reasonable and prudently incurred costs of unbundled RECs are incremental costs and have no avoided cost component.

Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect."

DNCP's 2014 REPS compliance report for compliance year 2013 stated that pursuant to G.S. 62-133.8(c)(2)e the Company provided renewable energy resources and compliance reporting services for the Town of Windsor.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact appears in DNCP's 2014 REPS compliance report for compliance year 2013 and in the testimony of DNCP witness Muchhala and the affidavit of Public Staff witness Floyd. In addition, the Commission takes judicial notice of information contained in NC-RETS.

DNCP's 2014 REPS compliance report was admitted into evidence as Muchhala Exhibit No. 1. This report provided the information required by Commission Rule R8-67(c) for DNCP and the Town of Windsor, for which DNCP has agreed to provide REPS compliance services. Public Staff witness Floyd stated in his affidavit that he reviewed DNCP's 2014 REPS compliance report and recommended that it be approved.

DNCP witness Muchhala testified that DNCP's 2012 retail electric sales were 4,114,540 MWh and the Town of Windsor's were 47,275 MWh, and that DNCP's 3% 2013 total REPS obligation amounted to 123,438 RECs, including 2,881 solar RECs (0.07% of 4,114,540 MWh). The Town of Windsor's 3% 2013 total REPS obligation amounted to 1,419 RECs, including 34 solar RECs (0.07% of 47,275 MWh). Public Staff witness Floyd stated in his affidavit that these numbers of RECs met the REPS requirements that 3% of 2012 retail sales must be matched with an equivalent number of RECs in 2013, including 0.07% of 2012 retail sales that must be matched with an equivalent number of RECs derived from solar energy. Witness Floyd confirmed that DNCP had placed these numbers of RECs in its own and the Town of Windsor's NC-RETS compliance sub-accounts. Witness Muchhala testified that out-of-state RECs may be used for 100% of DNCP's REPS compliance, but may not be used to meet more than 25% of the Town of Windsor's REPS requirements. DNCP complied with these limitations. NC-RETS further indicates that DNCP complied with the provisions of G.S. 62-133.8(b)(2)(e) and (c)(2)(d). No party disputed that DNCP and the Town of Windsor complied with their 2013 REPS requirements, and witnesses Muchhala and Floyd both stated that DNCP and the Town of Windsor met the 2013 REPS requirements.

Based on the foregoing and all the evidence of record, the Commission finds that DNCP and its wholesale customer, the Town of Windsor, for which DNCP is providing REPS compliance services, have fully complied with the requirements of the REPS for 2013, and that DNCP's 2014 REPS compliance report for compliance year 2013 should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact appears in DNCP's Application and in the testimony of DNCP witnesses Muchhala and Givens and the affidavit of Public Staff witness Eastwood.

Commission Rule R8-67(e)(3) provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its annual fuel charge adjustment proceedings, which is specified in Rule R8-55(c) for DNCP to be the 12-month period ending each June 30. Therefore, the test period to be used for this REPS cost recovery proceeding was the period July 1, 2013, through June 30, 2014.

Regarding the prospective rate period, Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period that "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." For DNCP, this is the calendar year. In its current fuel proceeding, Docket No. E-22, Sub 515, and in this proceeding, DNCP has proposed that its rate adjustments take effect on January 1, 2015, and remain in effect for a 12-month period.

DNCP's test period and billing period were not challenged by any party. Therefore, the Commission finds that the test period and rate period proposed by DNCP are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact appears in the testimony and exhibits of DNCP witnesses Muchhala and Givens and the affidavits of Public Staff witnesses Floyd and Eastwood.

Pursuant to G.S. 62-133.8(h)(1), "incremental costs" include, among other things, "all reasonable and prudent costs incurred by an electric power supplier to . . . (b) [f]und research that encourages the development of renewable energy, energy efficiency, or improved air quality, provided those costs do not exceed one million dollars ($1,000,000) per year." Whether specific test period or forecasted rate period expenditures to fund research are eligible for cost recovery through an annual rider pursuant to this provision is determined by the Commission on a case-by-case basis.

DNCP witnesses Muchhala and Givens described the status of the Company's micro-grid project, which the Commission approved in the Company's 2013 REPS rider proceeding, Docket No. E-22, Sub 503, as a research project qualifying for REPS rider cost recovery pursuant to G.S. 62-133.8(h)(1). DNCP's micro-grid project was constructed at the Company's Kitty Hawk district office beginning in February 2014, and was commissioned and placed in service for operation as a micro-grid in July 2014. A ribbon cutting was held July 25, 2014.

The micro-grid – as currently constructed and operating – integrates a behind-the-meter on-site diesel generator, a utility feed, one five-kilowatt (kW) horizontal-axis and three vertical-axis wind turbines (3-kW, 4-kW and 5-kW); a lithium ion battery with a 75-kWh storage capacity and 25-kW discharge rate; a 6-kW ground-mounted solar array; protective relays, inverters, proprietary control software, metering, and circuit breakers; and round-the-clock system monitoring. DNCP witness Muchhala explained that the Company plans to incorporate a small-scale (3-kW) fuel cell sized for residential and small commercial customer applications into the micro-grid during the 2015 rate period. The fuel cell addition is projected to be placed into service as an integrated component of the micro-grid in the summer of 2015. Company witness Givens supported the cost of the fuel cell addition to the micro-grid, as well as explained that qualified fuel cell property is eligible for federal investment tax credits, which will offset a portion of the capital cost of the fuel cell addition. The cost of the fuel cell addition to the micro-grid was filed confidentially under seal with the Commission. The Company will file its first annual report of the three-year demonstration period (2015 through 2017) with its 2015 REPS Report.

Public Staff witness Floyd stated in his affidavit that the Public Staff reviewed DNCP's micro-grid research costs, including the estimated costs of the fuel cell addition, as part of its investigation into DNCP's Application. Neither the Public Staff nor any party took issue with DNCP's testimony concerning the nature and costs of its micro-grid research activity nor questioned the reasonableness of the micro-grid costs included for recovery.

The Commission concludes that the research activities proposed by DNCP to be funded during the rate period are eligible research costs recoverable under G.S. 62-133.8(h)(1)(b), and that such research costs included in the Company's Rider RP revenue requirement are within the annual limit allowed by statute. Additionally, the Commission finds and concludes that DNCP should file annual project updates with the Commission detailing its micro-grid study results along with the Company's annual REPS compliance reports after each year of the three-year demonstration period (2015 through 2017).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 – 16

The evidence supporting these findings of fact is found in the testimony and exhibits of DNCP witnesses Muchhala, Givens, and Rice, and the affidavits of Public Staff witnesses Floyd and Eastwood.

DNCP witness Muchhala testified that the Company procured RECs to fully comply with its 2013 solar set-aside and general obligation REPS requirements, as well as the Town of Windsor's 2013 requirements. DNCP had not purchased bundled renewable energy for REPS compliance, and, therefore, 100% of its prudently incurred REC costs are incremental costs recoverable through the REPS rider. The Company is well-positioned to comply with its own 2014 solar set-aside, poultry set-aside, and general obligation requirements, as well as the Town of Windsor's solar and general obligation requirements. DNCP witness Muchhala initially testified that it was highly likely that the Company would be able to achieve 2014 swine waste resource set-aside compliance. However, in his rebuttal testimony, witness Muchhala explained that DNCP has joined other electric power suppliers in requesting a one-year delay of the 2014 swine set-aside requirement due to changes in projected swine waste resource REC availability by year-end 2014. In his Exhibit No. 2, witness Muchhala listed the suppliers from which DNCP expects to purchase RECs during the rate period, together with the amounts DNCP expects to pay to these suppliers.

Relying on the information presented in witness Muchhala's Exhibit No. 2, DNCP witness Givens developed the revenue requirements for both the REPS EMF period and the 2015 rate period. As explained by witness Muchhala, the REPS compliance costs used by witness Givens reflect DNCP's retail customers' REPS compliance costs and were net of the REC and non-REC costs incurred by DNCP for the Town of Windsor. Witness Givens presented the updated REPS EMF true-up period revenue requirement of $465,566 and the forecasted rate period revenue requirement of $1,022,618.

DNCP witness Rice then allocated the rate period and REPS EMF true-up period revenue requirements to the residential, commercial, and industrial customer classes and developed Rider RP and RPE rates to recover the class revenue requirements during the 2015 rate period.

Public Staff witnesses Floyd and Eastwood described the Public Staff's audit of DNCP's REPS costs and recommended approval of DNCP's proposed Rider RP and RPE rates. As part of his review, Public Staff witness Floyd stated in his affidavit that DNCP appropriately allocated energy efficiency credits (EECs) from its North Carolina EE programs to the customer classes creating the EECs. Witness Floyd also generally noted disparities between the number of EECs DNCP had projected in its recent annual REPS plans and the number of EECs actually available and proposed to be used for REPS compliance in DNCP's 2014 REPS report. Witness Floyd recommended that it would be more appropriate for DNCP's REPS compliance plans and reports to be more consistent with regard to its projection and subsequent pursuit of retirement of EECs. DNCP witness Muchhala's rebuttal testimony noted that EE penetrations in the early years of program deployment had, in certain cases, been less than had been projected and that the recent suspension and closure of certain EE programs had also contributed to DNCP experiencing less EEC creation than initially anticipated. Witness Muchhala testified that DNCP agrees with the Public Staff's suggestion for improved consistency and will evaluate its EE program penetration projections going forward to ensure EEC projections presented in the Company's annual REPS compliance plan more closely align with the EECs proposed to be retired in future REPS reports.

Witness Floyd stated in his affidavit that he reviewed DNCP's calculation of the revenue requirement and rates, and that DNCP properly calculated the following monthly charges for the forecast rate and EMF components of the total REPS rate, including regulatory fee:

Customer Class	**Forecast Rate (Rider RP)**	**EMF Rate (Rider RPE)**	**Total REPS Rate**
Residential	$0.47	$0.22	$0.69
Commercial	$2.09	$0.95	$3.04
Industrial	$14.26	$6.39	$20.65

Public Staff witness Eastwood also recommended that the REPS EMF rates presented above be approved based upon her investigation of DNCP's Application. The above Rider RP and RPE rates are consistent with the Rider RP and RPE rates presented in witness Rice's Schedule 7.

Based upon the testimony of DNCP witnesses Muchhala, Givens, and Rice, the affidavits of Public Staff witnesses Floyd and Eastwood, and the entire record of this proceeding, the Commission finds and concludes that DNCP's proposed REPS EMF period and rate period revenue requirements and proposed Rider RPE and RP rates, as agreed to by the Public Staff, are appropriate to be charged during the 2015 rate period. The Commission also finds that DNCP's approach to crediting EECs among its customer classes is reasonable. The Commission understands that DNCP's forward looking EEC projections in its REPS plans may not always be consistent with actual EE program penetrations (and EEC creation) presented in its REPS reports due to a variety of factors, including changes to the Company's EE program portfolio in North Carolina. DNCP's commitment to evaluate its EE program penetration projections in response to the Public Staff's concerns is reasonable and appropriate. Therefore, the Commission will require DNCP to perform such an evaluation and include testimony regarding its conclusions with its 2015 REPS rider application.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact appears in the testimony of DNCP witness Rice and the affidavit of Public Staff witness Floyd.

DNCP witness Rice testified that for purposes of developing the per-account REPS charges, the Company defined a "customer account" as a "service point" or "application of a tariff." Witness Rice stated that DNCP rate schedules 1W, 1DF, 26, 30T, 7, and SG are not considered "accounts" for purposes of the per-account charge because these rate schedules are generally secondary accounts and customers on these rate schedules will pay a per-account charge under another primary tariff connected with these rate schedules. Witness Rice also testified that if a customer has a service point on contiguous property with the same service address, premises, and name, then that account may be deemed to be auxiliary and not subject to the REPS Riders RP and RPE if the Company is notified by the customer. Upon written notification from the customer, accounts meeting these criteria will be coded in the DNCP billing system to allow the customer to be charged only a single monthly REPS charge at the customer's primary service point.

Public Staff witness Floyd did not oppose the Company's approach to determining a customer account.

Based upon the testimony of DNCP witness Rice, the affidavit of Public Staff witness Floyd, and the entire record of this proceeding, the Commission finds and concludes that DNCP's approach to determining a customer account for purposes of calculating its per-account REPS charges is reasonable and appropriate. The Commission also approves DNCP's definition of an "auxiliary account" as well as DNCP's proposed approach to allowing a customer to inform DNCP in writing if it is the account holder for an auxiliary account that should be excluded from the REPS charge.

IT IS, THEREFORE, ORDERED as follows:

1. That DNCP shall establish a REPS rider RP as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning January 1, 2015, and expiring December 31, 2015;

2. That DNCP shall establish a REPS EMF rider RPE as described herein, and that this rider shall remain in effect for a 12-month period beginning January 1, 2015, and expiring December 31, 2015;

3. That DNCP 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-22, Subs 506, 513, and 515, and the Company shall file such notice for Commission approval as soon as practicable, but not later than three (3) working days after the Commission issues orders in all of the above-referenced dockets;

4. That DNCP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order as soon as practicable;

5. That DNCP's 2014 REPS compliance report is hereby approved and the RECs and EECs in DNCP's and the Town of Windsor's 2013 compliance sub-accounts in NC-RETS shall be retired;

6. That DNCP shall file project updates to the Commission detailing its micro-grid study results with its annual REPS compliance reports; and

7. That DNCP shall evaluate its EE program projections and provide testimony regarding those projections in its 2015 REPS rider application.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-7, SUB 1055

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Duke Energy Carolinas, LLC,	)	
for Approval of Proposed Small Business	)	ORDER APPROVING PROGRAM
Energy Saver Program	)	

BY THE COMMISSION On May 16, 2014, Duke Energy Carolinas, LLC (DEC), filed an application for approval of its Small Business Energy Saver program (Program) as an energy efficiency (EE) program under G.S. 62-133.9 and Commission Rule R8-68.

The Program was developed and modeled after the Small Business Energy Saver program of Duke Energy Progress, Inc., approved in Docket No. E-2, Sub 1022. The Program is designed to achieve energy savings through the installation of certain energy efficiency (EE) measures such as lighting, refrigeration, and HVAC (heating, ventilation, and air conditioning) measures. Under the Program, DEC will provide incentives to a Company-authorized vendor, who will install EE measures in commercial buildings with average demands of up to 100 kilowatts (kW). Customers will receive a free energy assessment designed to identify specific lighting, refrigeration, or HVAC measures that could help them reduce energy consumption. Customers would then contract with the vendor to install the identified measures.

DEC projects the average annual kW and kilowatt-hour (kWh) savings from the Program to be 26.9 megawatts (MW) per year and 111,724 megawatt-hours (MWh) per year over the first five years of the Program. The Program will be available throughout DEC's entire service territory to any non-residential customer served under a general service or industrial rate schedule who owns, or is a tenant of, an existing commercial building. DEC will also limit the availability of the Program to five existing commercial buildings associated with any one individual business entity.

The Program is designed as a "pay-for-performance" program. Participants will not receive direct incentive payments, rather the Company-authorized vendor would receive payment from

DEC based on the energy savings associated with the measures actually installed. DEC would pay the vendor up to 80% of the installed costs of the measures, with the vendor discounting the overall project price charged to the participant. Participants would be responsible for the balance of the project costs.

DEC requested that the Commission (1) approve the Program and corresponding tariff; (2) find that the Program meets the requirements for a new EE program consistent with Commission Rule R8-69; (3) find that all costs incurred by the Company associated with the Program should be eligible for consideration for cost recovery through the Company's annual demand-side management/energy efficiency (DSM/EE) rider in accordance with Commission Rule R8-69(b); and (4) approve the proposed utility incentives for inclusion in the annual DSM/EE rider in accordance with Commission Rule R8-69.

The Public Staff filed comments on the Program on July 7, 2014 (Comments). The Public Staff noted that the Program appeared to be cost-effective under all four cost effectiveness tests, the Total Resource Cost (TRC), Utility Cost (UC), Participant, and Ratepayer Impact Measure (RIM) tests. The Public Staff recommended that the Commission approve the Program as a "new" EE program pursuant to Commission Rule R8-68, determine that the Program is eligible for consideration of recovery of program costs, net lost revenues, and a portfolio performance incentive related to the Program in accordance with the Mechanism, and determine the appropriate recovery of program costs and net lost revenues associated with the Program in the annual DSM/EE rider proceeding consistent with G.S. 62-133.9, Commission Rule R8-69, and the Mechanism.

The Public Staff recommended the Commission require DEC to: (a) provide the Public Staff with copies of the standard vendor contract, participant agreement, and any other Program-related forms prior to initiating the Program; (b) ensure that the full amount of the portion of the payments to the Company-authorized vendor who install EE measures under the Program that are designated as participant incentive be passed through to the participating customer and report to the Commission regarding this requirement in its annual DSM/EE rider filing; and (c) include in the first EM&V report for the Program, an analysis of the appropriateness of the initial baseline measures used to calculate the initial estimates of program impacts.

The Public Staff also recommended that the Commission require DEC to include in its annual cost recovery proceeding the following information: (a) the total cost, the amount of the participant incentive paid by DEC to the vendor, and the amount of incentive received by each participant for each project; (b) the number of customers determined to be ineligible for participation and the reason for ineligibility; and (c) any changes in the availability of the Program or to the amount of participant incentives.

No other party filed an intervention, a protest, or comments.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on August 11, 2014. The Public Staff recommended that the Commission approve the Program as a "new" EE program pursuant to Commission Rule R8-68, determine that the Program is eligible for consideration of recovery of program costs, net lost revenues, and a PPI related to the Program in accordance with the Mechanism, and determine the appropriate recovery of program costs and net lost revenues associated with the Program in the annual DSM/EE rider proceeding consistent with G.S. 62-133.9, Commission Rule R8-69, and the Mechanism. The Public Staff also proposed that the Commission require the Company to comply with the recommendations made in its Comments as delineated above.

Based on the foregoing, the Commission is of the opinion that DEC's Small Business Energy Saver Program should be approved as a new EE program pursuant to Commission Rule R8-68.

It appears to the Commission that the Program, as proposed, has the potential to encourage EE achieve energy savings through the installation of certain energy efficiency (EE) measures such as lighting, refrigeration, and HVAC (heating, ventilation, and air conditioning) measures by non-residential customers served under a general service or industrial rate schedule who own, or are a tenant of, an existing commercial building. The Commission also recognizes that the proposed Program appears to be cost-effective under the TRC, UC, Participant, and RIM tests.

The Commission is of the opinion that the appropriate ratemaking treatment for the Program, including program costs and the level of incentives (net lost revenues and PPI) should be determined when DEC seeks cost recovery in a future DSM/EE rider proceeding in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Mechanism approved in Docket No. E-7, Sub 1032.

The Commission finds and concludes that DEC should: (a) provide the Public Staff with copies of the standard vendor contract, participant agreement, and any other Program-related forms prior to initiating the Program; (b) ensure that the full amount of the portion of the payments to the

Company-authorized vendor who install EE measures under the Program that are designated as participant incentive be passed through to the participating customer and report to the Commission regarding this requirement in its annual DSM/EE rider filing; and (c) include in the first EM&V report for the Program, an analysis of the appropriateness of the initial baseline measures used to calculate the initial estimates of program impacts.

The Commission also finds and concludes that DEC should include in its annual cost recovery proceeding the following information: (a) the total cost, the amount of the participant incentive paid by DEC to the vendor, and the amount of incentive received by each participant for each project; (b) the number of customers determined to be ineligible for participation and the reason for ineligibility; and (c) any changes in the availability of the Program or to the amount of participant incentives.

IT IS, THEREFORE, ORDERED as follows:

1. That the Small Business Energy Saver Program shall be, and is hereby, approved as a new EE program pursuant to Commission Rule R8-68.

2. That the Commission shall determine the appropriate ratemaking treatment for the Program, including its program costs and incentives (net lost revenues and PPI), when DEC seeks cost recovery for the Program in a future DSM/EE rider proceeding in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Mechanism approved in Docket No. E-7, Sub 1032.

3. That DEC shall file its proposed Small Business Energy Saver Program tariff with the effective date to be within 10 days following the date of this Order.

4. That DEC shall comply with the recommendations made by the Public Staff in its Comments on the Program filed June 25, 2014 as set out above.

ISSUED BY ORDER OF THE COMMISSION.
This the _13th_ day of August, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Bryan E. Beatty did not participate in this decision.

DOCKET NO. E-2, SUB 1030

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, Inc., for	)	
Approval of Demand-Side Management and	)	FINAL ORDER APPROVING
Energy Efficiency Cost Recovery Rider	)	DSM/EE RIDER
Pursuant to G.S. 62-133.9 and Commission	)	
Rule R8-69	)	

HEARD: Tuesday, September 17, 2013, at 11:15 a.m., and Wednesday, September 18, 2013, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

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For the Southern Alliance for Clean Energy:

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For the Using and Consuming Public:

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BY THE COMMISSION: General Statute 62-133.9(d) authorizes the Commission to approve an annual rider to the rates of electric public utilities to recover all reasonable and prudent costs incurred for the adoption and implementation of new demand-side management 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 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 Commission Rule R8-68. Under Commission Rule R8-69, such rider consists of the utility's forecasted costs during the rate period, similarly forecasted performance incentives (including net lost revenues) as allowed by the Commission, and an experience modification factor (EMF) rider to collect the difference between the utility's actual reasonable and prudent costs and incentives incurred and earned during the test period and the actual revenues realized during the test period under the DSM/EE rider (based on previous forecasts) then in effect.

Docket No. E-2, Sub 1030

On June 12, 2013, Duke Energy Progress, Inc. (DEP or the Company), filed an application and the associated testimony and exhibits of Robert P. Evans for the approval of a DSM/EE rider to recover reasonable and prudent forecasted DSM/EE costs, carrying costs, incremental administrative and general (A&G) costs, capital costs, taxes, and incentives, including net lost revenue (NLR) and the program performance incentive (PPI). In addition, DEP asked for approval of a DSM/EE EMF rider and, pursuant to Commission Rule R8-69(b)(2), recovery through the DSM/EE EMF of its post-test-year costs, including carrying costs and incentives incurred up to 30 days prior to the hearing in this proceeding.

On June 25, 2013, the Commission issued an Order scheduling a public hearing in this matter for September 17, 2013, immediately following the 9:30 a.m. hearings in Docket No. E-2, Subs 1031 and 1032, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice. On August 28, 2013, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's June 25, 2013 Order.

The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On June 18, 2013, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted by Commission Order issued June 24, 2013. On June 28 2013, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by Commission Order issued July 3, 2013. On August 29, 2013, the Southern Alliance for Clean Energy (SACE) filed a petition to intervene, which was granted by Commission Order issued August 30, 2013.

On August 15, 2013, DEP filed the supplemental testimony and exhibits of Robert P. Evans. On August 26, 2013, the Public Staff filed a motion for extension of time to file its testimony, which was allowed. On September 4, 2013, the Public Staff filed the testimony of Michael C. Maness and Jack L. Floyd, and SACE filed the testimony of Natalie Mims. On September 13, 2013, DEP filed the rebuttal testimony and exhibits of Robert P. Evans and the rebuttal testimony of Jay W. Oliver.

On September 17, 2013, the hearing was held as scheduled. No public witnesses appeared at the hearing.

On October 11, 2013, DEP filed late-filed exhibits pursuant to requests by the Commission, the Public Staff, and NCSEA during the evidentiary hearing. On October 17, 2013, NCSEA filed a letter in lieu of a post-hearing brief. On October 25, 2013, the Commission issued an Order Requiring Additional Information, which Order required DEP to file additional information on or before November 1, 2013. Also on October 25, 2013, DEP filed a proposed order, and the Public Staff and SACE each filed briefs. On November 1, 2013, DEP filed the information that was required by the Commission's October 25, 2013 Order.

On November 22, 2013, the Commission issued a Notice of Decision and Order in which it approved DEP's proposed DSM/EE rates and EMF for service rendered on or after December 1, 2013. That Order stated that a final Order, including findings of fact and conclusions, would be issued at a later date. The instant Order is that final order, and the time for filing an appeal from the decision of the Commission shall begin to run on the date of issuance of this Order.

On November 26, 2013, DEP filed a proposed joint notice to customers of change in rates. On November 27, 2013, DEP filed its compliance tariffs for service rendered on and after December 1, 2013. Both of these filings address rate changes that the Commission had approved in this docket, and Docket No. E-2, Subs 1031 and 1032. On December 2, 2013, the Commission issued an Order Approving Notice to Customers of Change in Rates. On December 2, 2013, DEP filed its Residential Service Energy Conservation Discount Rider RECD-II, stating that the Company had inadvertently omitted the rider from its November 27, 2013 submittal.

Other Pertinent Orders: Docket No. E-2, Subs 931 and 926

On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications in DEP's first DSM/EE rider proceeding (Sub 931 Order). In that Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation), between DEP, the Public Staff, and Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, Wal-Mart), setting forth the terms and conditions for approval of DSM/EE measures and the annual DSM/EE rider proceedings pursuant to G.S. 62-133.9 and Commission Rules R8-68 and 69. The Stipulation included a Cost Recovery and Incentive Mechanism for Demand-Side Management and Energy Efficiency Programs (Mechanism), which was modified by the Commission in its Sub 931 Order, allowing DEP to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and EE measures in accordance with G.S. 62-133.9, Commission Rules R8-68 and 69, and the additional principles set forth in the Mechanism.

On July 13, 2009, DEP filed a Motion for Reconsideration and Stay regarding certain decisions made by the Commission in Docket No. E-2, Subs 926[1] and 931.[2] The request for reconsideration filed by DEP involved, among other things, the Commission's decision that industrial and large commercial customers may not opt-out of cost recovery with respect to DEP's DSDR program. On November 25, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Granting Motions for Reconsideration in Part determining, among other things, that industrial and large commercial customers could opt-out of DEP's DSM and EE programs and would not be charged, via a rider, for the DSDR program (which the Commission had already determined to be an EE program).

In the present proceeding, based upon DEP'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. DEP 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

[1] In Docket No. E-2, Sub 926, the Commission approved DEP's application for approval of its Distribution System Demand Response (DSDR) program.

[2] Motions for reconsideration were also filed by three intervenors: Carolina Utility Customers Association, Inc. (CUCA), Wal-Mart, and the Carolina Industrial Customers for Fair Utility Rates II, in those dockets.

of the Commission as a public utility. DEP 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, 2012, through March 31, 2013.

3. The rate period for purposes of this proceeding is the 12-month period December 1, 2013, through November 30, 2014.

4. Pursuant to Commission Rule R8-69(b)(2), DEP is permitted to include in its DSM/EE EMF rider its post-test-year over- or under-recovery of DSM/EE costs, including NLR and the PPI, experienced up to 30 days prior to the hearing. In this proceeding, such period is referred to as the prospective period, and is April 1, 2013, through July 31, 2013.

5. For purposes of this proceeding, DEP has requested approval for the recovery of costs and incentives, where applicable, related to the following DSM/EE programs: DSDR; EnergyWise^{SM}; Commercial, Industrial, and Governmental (CIG) Demand Response; Residential Home Advantage (RHA); Residential Home Energy Improvement; Residential Low Income-Neighborhood Energy Saver; CIG EE; Energy Efficiency Lighting; Residential Energy Efficiency Benchmarking; Residential Appliance Recycling (ARP); Residential Solar Water Heater Pilot; Compact Fluorescent Light (CFL) Pilot, Small Business Energy Saver; and Residential New Construction.

6. DEP requested recovery of incremental A&G expenses not directly related to specific DSM or EE programs. The incremental A&G expenses included certain general education and awareness (GEA) costs. The level of A&G costs (including GEA costs) proposed by DEP in this proceeding is reasonable. It is appropriate for DEP to recover these incremental A&G costs over a three-year period pursuant to the Mechanism. DEP performed a market survey to assess the effectiveness of DEP's GEA activities, as ordered in Docket No. E-2, Sub 1019, and filed the results with the Commission. The GEA study shows that DEP's GEA initiatives are effective and no further market survey is required at this time. It is appropriate for DEP to report on its GEA costs and activities, and for the Public Staff to review that information, in DEP's future DSM/EE rider proceedings.

7. The evaluation, measurement, and verification (EM&V) analyses and reports prepared by DEP are adequate for purposes of this proceeding, except that the Company shall implement the Public Staff's recommendations regarding additional true-up of PPI and NLR calculations for the 2010 vintage of DEP's ARP in its 2014 DSM/EE rider application.

8. DEP requested the recovery of NLR and PPI in the amount of $20,679,807 for the test period (April 2012 through March 2013), and $4,449,007 for the prospective period (April 2013 through July 2013), reduced by $5,993,407 related to the prior case's prospective period (April 2012 through July 2012), and $18,058,582 for the rate period (December 2013 through November 2014). DEP's proposed recovery of NLR and PPI is consistent with the Sub 931 Order, as modified by the Commission's November 25, 2009, Order Granting Motions for

Reconsideration in Part, and is appropriate, subject to further review to the extent allowed in the Stipulation and Mechanism.

9. For purposes of the DSM/EE rider to be set in this proceeding and subject to review in DEP's future DSM/EE rider proceedings, DEP's reasonable and appropriate estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, is $75,392,680, and this is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement.

10. For purposes of its DSM/EE EMF rider, DEP's reasonable and prudent North Carolina retail test year costs and incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, is $70,351,366. The portion of this total amount that has been or is being recovered for the prospective period in the 2012 rider proceeding is $16,635,382. Subject to review in DEP's next annual DSM/EE rider proceeding, DEP's North Carolina retail DSM/EE program amount for the 2013 prospective period, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, and NLR, is $17,226,402. Therefore, $70,942,388 is the appropriate cost and incentive total to use to develop the DSM/EE EMF revenue requirement. The reasonable and appropriate amount of test year and prospective period DSM/EE rider revenues, adjusted for PPI changes, interest and uncollectables, is $71,291,616. Therefore, the aggregate DSM/EE under-recovery for purposes of this proceeding is $349,228.

11. After allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding gross receipts taxes (GRT) and the North Carolina regulatory fee (NCRF), are as follows:

RATE PERIOD:

Residential	$48,039,813
General Service	26,891,475
Lighting	461,392
Total	$75,392,680

DSM/EE EMF

Residential	$(1,606,203)
General Service	1,286,113
Lighting	(29,138)
Total	$ (349,228)

12. The appropriate and reasonable North Carolina retail class level kilowatt-hour (kWh) sales for use in determining the DSM/EE rate and DSM/EE EMF in this proceeding are as follows:

Rate Class	kWh Sales
Residential	15,450,380,543
General Service	10,571,063,990
Lighting	433,707,891

13. The appropriate DSM/EE EMF rates for the Residential and Lighting rate classes, excluding GRT and the NCRF, are decrements of 0.010 cents per kWh and 0.007 cents per kWh, respectively. The appropriate DSM/EE EMF rate for the General Service rate class, excluding GRT and the NCRF is an increment of 0.012 cents per kWh.

14. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period for the Residential, General Service, and Lighting rate schedules, excluding GRT and the NCRF, are increments of 0.297 cents per kWh, 0.227 cents per kWh, and 0.101 cents per kWh, respectively. Including GRT and the NCRF, the forward-looking rates for the Residential, General Service, and Lighting rate schedules are increments of 0.307 cents per kWh, 0.235 cents per kWh, and 0.104 cents per kWh, respectively.

15. The appropriate combined DSM/EE and EMF riders for the billing period, including GRT and the NCRF, are 0.297 cents per kWh for Residential customers, 0.247 cents per kWh for General Service customers, and 0.097 cents per kWh for Lighting customers.

16. DEP included the information regarding the Solar Hot Water Pilot program as ordered in the Sub 1019 Order. Costs associated with the approved Solar Hot Water Pilot program are appropriately included in the test and rate periods.

17. The recommendations of Public Staff witness Floyd regarding future EM&V reports for the Energy Efficiency Lighting program and the Residential Appliance Recycling program are reasonable, as modified by the agreement of the parties as to using Carolinas-specific data, and DEP should incorporate them to the extent that the benefits exceed the costs. If DEP determines that the costs of following a recommendation outweigh the benefits, it should discuss its cost-benefit analysis with the Public Staff and include a description of the analysis in the EM&V report.

18. When the Commission approved DEP's DSDR program as an EE program in Docket No. E-2, Sub 926, it was aware that the program, as it was described in that application proceeding, would require ongoing O&M expenses and capital investment. The 247-MW peak reduction expected as a result of the completed implementation of DSDR, now anticipated by mid-2014, continues to be in the public interest. DSDR is expected to provide an ever-increasing amount of cost-effective peak energy savings. It is in the public interest for DEP to design and build all distribution system expansions consistent with DSDR and capable of contributing to DSDR's energy and capacity savings.

19. DEP's costs incurred to install, operate, and expand the DSDR program and its related costs to maintain DSDR benefits on its distribution system should be recovered through the DSM/EE rider. It is in the public interest to allow DEP to recover DSDR growth or expansion costs through the DSM/EE rider. Ongoing costs, including replacement costs for

DSDR equipment, shall be recovered through the DSM/EE rider. After installation of DSDR, the resulting DEP distribution system will be comprised of both traditional non-DSDR equipment and equipment that is incremental to DSDR. In order to assure that only DSDR-related costs are charged to and recovered through the DSM/EE rider, DEP should develop reasonable methods to allocate the portion of total distribution system costs that are DSDR-related to the DSM/EE rider.

20. The Company did not propose to recover any NLR incentives for its DSDR program in this proceeding. It is not necessary for the Commission to decide the issue of NLR for DSDR at this time.

21. It is appropriate for DEP to establish a collaborative similar to the one in place for Duke Energy Carolinas, LLC (DEC), in order to discuss with interested stakeholders potential new programs, or modifications to existing programs, that would help DEP achieve additional EE savings. It is appropriate for the collaborative to consider and develop a position regarding either a limited study or survey of customers who have opted-out of DEP's DSM/EE programs and for DEP to report the results and conclusions or recommendations as part of its 2014 DSM/EE rider filing.

22. It is not appropriate at this time to require DEP to develop a GEA program to notify customers of anticipated system peaks and urge them to refrain from using electricity during such peaks. Rather, it is appropriate for the collaborative discussed above to consider whether and how such a program should be proposed.

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

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The rate period, test period, and prospective period proposed by DEP 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 DEP's application, the testimony and exhibits of DEP witness Evans, the testimony of Public Staff witness Floyd, and various Commission orders.

In DEP witness Evans' direct testimony and exhibits filed on June 12, 2013, he stated that DEP is requesting the recovery of costs associated with the following DSM/EE programs: DSDR; EnergyWise^{SM}; CIG Demand Response; RHA; Residential Home Energy Improvement; Residential Low Income-Neighborhood Energy Saver; CIG EE; Energy Efficiency Lighting; Residential Energy Efficiency Benchmarking; ARP; Residential Solar Water Heater Pilot; CFL Pilot, Small Business Energy Saver, and Residential New Construction.

In his testimony, Public Staff witness Floyd also listed the DSM/EE programs (and pilots) for which DEP seeks cost recovery and noted that each of these programs (or pilots) 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. Public Staff witness Floyd also noted that the Residential

Home Advantage, CFL Pilot and the Solar Water Heater Pilot have been cancelled or terminated, yet the related costs are appropriate to include in the DSM/EE rider.

Thus, each of the programs listed by witnesses Evans and Floyd has received Commission approval as a new DSM or EE program (or pilot) and is, therefore, eligible for cost recovery in this proceeding under G.S. 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact can be found in the testimony and exhibits of DEP witness Evans and the testimony of Public Staff witness Floyd.

The appropriate A&G amounts for use in the development of the EMF and rate periods were provided by DEP witness Evans. In his Rebuttal Exhibit No. 1, witness Evans provided $2,067,737 as the A&G value appropriate for use in the development of DEP's EMF rate. Also in his rebuttal exhibit, he provided $2,354,233 as the A&G value appropriate for use in the development of DEP's DSM/EE rate.

Witness Evans stated that during the test period, DEP's GEA initiatives included both newspaper and online advertising, a Twitter social media account, the Save Energy and Money website, Customized Home Energy Report (CHER), the e-SMART Kids website for school-age children, participation in community events, and distribution of informational flyers and other printed materials to customers. During the test period, Save Energy and Money ad messages were published 78 times, achieving over 3.4 million impressions, generating more than 156 million views and receiving more than 150,000 clicks. Search advertising for keywords related to the Company and energy efficiency generated nearly 2.7 million potential views by customers and more than 190,000 clicks. DEP sent letters to 55,000 customers about the CHER, and more than 40,000 customers responded by completing a CHER.

Public Staff witness Floyd testified that DEP's A&G costs include expenditures for GEA initiatives. He testified that DEP's GEA initiatives educate the public about DSM and EE and raise customer awareness about DSM and EE programs. He stated that most of DEP's GEA spending is related to its CHER initiative, a tool that steers customers toward specific programs. Witness Floyd testified that he believed that DEP's GEA costs are reasonable.

Witness Floyd also testified regarding the findings of a GEA study, which the Commission had ordered on March 5, 2013, and which the Company filed on May 24, 2013. He stated that the findings suggest that DEP's CHER and other GEA initiatives make customers more aware of EE, leading to many customers taking some action to implement EE. He also stated that it is reasonable for DEP to report its GEA initiatives, by volume of activity and costs, in its future DSM/EE rider proceedings, but that it does not seem worthwhile to incur substantial additional costs for further study of the effectiveness of DEP's GEA initiatives. Finally, witness Floyd said the Public Staff will continue to review DEP's GEA costs, as well as other A&G costs, in the Company's DSM/EE rider proceedings.

No party opposed DEP's GEA expenditures or incremental A&G costs. Therefore, based on the testimony of witness Evans and witness Floyd the Commission concludes that the expenditures are reasonable and prudent and that it is appropriate for DEP to recover its incremental A&G costs over a three-year period pursuant to the Mechanism.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for these findings of fact can be found in the testimony and exhibits of DEP witness Evans, the testimony of Public Staff witness Floyd, and the Commission's Order in Docket No. E-2, Sub 1019.

In his direct testimony, DEP witness Evans testified that since the last rider proceeding, DEP's independent third party EM&V consultant, Navigant, completed its assessments of the 2010 and 2011 vintage periods of DEP's Residential Home Advantage program, the 2010 and 2011 vintage periods of DEP's Home Energy Improvement Program, the 2011 vintage period of its ARP, the 2010 and 2011 vintage periods of its EnergyWise^{SM} Program, the 2011 vintage of its Residential Benchmarking Program, and its 2010 and 2011 vintage periods of its CIG Energy Efficiency Program.

Public Staff witness Floyd testified that the Public Staff had reviewed the EM&V reports filed by DEP prior to June 1, 2013, and used by DEP to calculate the DSM/EE rider. He recommended no further changes to the net energy and capacity savings derived from the EM&V for the 2010 and 2011 vintages of the Residential Energy Efficient Lighting program, the Winter 2011 and 2012 and the Summer 2011 vintages of the EnergyWise^{SM} program, the 2010 and 2011 vintages of the Residential Home Energy Improvement program, the August 2011 through July 2012 vintage of DEP's Residential EE Benchmarking Program, the 2010 and 2011 vintages of the CIG EE program, and, with the exceptions discussed below, the 2010 and 2011 vintages of the ARP. Thus he deemed the EM&V for these program vintage combinations to be complete. (He also made two specific recommendations regarding future EM&V reports for both the ARP and Energy Efficiency Lighting program, which are addressed later in this Order.)

Based on these EM&V reports, DEP reevaluated the Total Resource Cost (TRC) test and the Utility Cost Test (UCT) cost-effectiveness tests for these program vintages. Cost-effectiveness tests are first used to evaluate a DSM or EE program as a resource option, and later to reevaluate the PPI. With some exceptions, programs or measures with a TRC of less than 1.0, at the time of the cost recovery proceeding, are ineligible for PPI. The levelized PPIs for the program vintages were recalculated using revised cost-effectiveness results resulting from EM&V. In addition to the changes in PPI amounts, EM&V-based impacts to the Company's NLR values were recognized.

Public Staff witness Floyd testified that he had observed the operation of the database DEP used to track the capacity and energy savings data of its DSM/EE programs; he had confirmed that the data properly flowed into the calculations of net present values (NPV) that serve as the basis for the NLR and PPI calculations. He tracked the data derived from EM&V as they were incorporated into the database, NPV calculations, and finally the rider calculation. Witness Floyd stated his belief that DEP is appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

Public Staff witness Floyd testified that DEP had followed all of the recommendations he had made as to EM&V reports as reflected in the Commission's Order in Docket No. E-2, Sub 1019, with the exception of his recommendation that the Company true-up its calculation of PPI or NLR for the 2010 vintage of the ARP. The Company had filed two separate EM&V reports evaluating separate vintages of the ARP. The first EM&V report (2010 report) was filed January 3, 2012, and it evaluated the 2010 vintage. DEP filed the second report addressing the 2011 vintage (2011 report), on February 1, 2013. The 2011 report used more advanced protocols to evaluate the 2011 vintage measures. Both reports were filed in Docket No. E-2, Sub 970.

Witness Floyd testified that DEP did not true up its calculation of PPI or NLR for the 2010 vintage of the ARP based on the levels of free ridership and replacement that were determined in the 2011 EM&V report for the ARP as represented in the net-to-gross (NTG) adjustment factor, and that the differences were largely due to the change in the Uniform Methods Project protocol for the evaluation of refrigerator recycling programs. Witness Floyd testified that DEP should have applied the new EM&V protocols to its 2010 report for the ARP, even though such protocols were not in existence at the time the 2010 EM&V report was prepared.

Witness Floyd noted that he had made several recommendations regarding DEP's future EM&V reports in Docket No. E-2, Sub 1019. One recommendation was that the Company should address free ridership and induced replacement issues in the ARP, and that it should apply those results retrospectively to the 2010 vintage. He stated that in its Order in that docket the Commission agreed with his recommendations for future EM&V reports:

> That [DEP] shall incorporate the recommendations of Public Staff witness Floyd regarding future EM&V reports to the extent that the benefits exceed the costs.[1]

Witness Floyd testified that Table ES-4 of the 2011 report suggested the 2011 NTG adjustment factors for refrigerators and freezers are 21 percent and 16 percent less, respectively, than the deemed NTG adjustment factors used in DEP's 2010 report. He stated that the differences were largely due to the change in the Uniform Methods Project protocol for the evaluation of refrigerator recycling programs, which had been "updated to account for factors such as induced replacement and secondary markets."

In its October 25, 2013 brief, the Public Staff stated that it generally agrees with DEP that the Company should not be required to conduct repeated true-ups of vintage years after the initial EM&V report and true-up. Even so, because the Public Staff had stated in the Sub 1019 proceeding that the vintage 2010 report was inadequate and that the Company's consultant was already in the process of evaluating the inadequacies for its next report, the Public Staff believed the inadequacies should be corrected in the 2013 cost recovery proceeding by applying the protocols in the 2011 report back to the 2010 vintage year. The Public Staff argued that it had identified the inadequacy of the free ridership and induced replacement analysis and that the Company had not offered any rebuttal to its recommendation to apply revised 2011 EM&V protocols back to the 2010 vintage. The Public Staff noted that the Commission's Order in the Sub 1019 docket stated that witness Floyd's EM&V recommendations should be adopted to the extent that the costs did not outweigh

[1] Ordering paragraph 9 of the November 27, 2012 Order in Docket No. E-2, Sub 1019.

the benefits. Since the Company's consultant was already in the process of making the EM&V protocol changes for the 2011 vintage report, there was no indication that the cost of making such changes to the 2010 report would outweigh the benefits. The Public Staff argued that the Company's failure to apply the revised EM&V protocol used in the 2011 report to the 2010 vintage is contrary to the Commission's Sub 1019 Order.

In his rebuttal testimony, DEP witness Evans testified that the additional, retroactive true-up proposed by the Public Staff is unwarranted because the 2010 vintage of the ARP program was trued-up in Docket No. E-2, Sub 1019, using the EM&V protocols that were in place at the time the report was prepared. He stated that the 2010 vintage EM&V report for the ARP was filed with the Commission on January 3, 2012, whereas the protocol argued for by the Public Staff was not published until April 2013. DEP witness Evans further testified that the Mechanism approved by the Commission in Docket No. E-2, Sub 931 for cost recovery and incentives for DEP's EE and DSM programs provides that NLR and PPI "shall be trued-up in the first R8-69 proceeding following the completion and review of a program's or measure's impact evaluation," and that the Public Staff's recommendation would violate the Commission's Order approving the Mechanism in Sub 931.

Based on the testimony and evidence cited above, the Commission finds that the net energy and capacity savings derived from DEP's EM&V for the 2010 and 2011 vintages of the Residential Energy Efficient Lighting program, the Winter 2011 and 2012 and the Summer 2011 vintages of the EnergyWise^{SM} program, the 2010 and 2011 vintages of the Residential Home Energy Improvement program, the August 2011 through July 2012 vintage of DEP's Residential EE Benchmarking Program, the 2010 and 2011 vintages of the CIG EE program; and the 2011 vintage of the ARP should be considered to be complete. The Commission further concludes that DEP appropriately incorporated the results of those EM&V reports into the DSM/EE rider calculations. However, the Commission agrees with the Public Staff that DEP should be required to revise its 2010 vintage EM&V report for the ARP to incorporate the new protocols for that program and should adjust its related NLR and PPI calculations in its next DSM/EE rider application.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-15

The evidence for these findings can be found in the testimony and exhibits of DEP witness Evans, the testimony of Public Staff witness Floyd, and the testimony of Public Staff witness Maness.

In DEP witness Evans' supplemental direct testimony and exhibits filed on August 15, 2013, he calculated DEP's North Carolina retail test period (April 2012 through March 2013) DSM/EE NLR and PPI as $20,679,807, DEP's North Carolina retail prospective period (April 2013 through July 2013) DSM/EE NLR and PPI as $4,449,007, and the 2012 DSM/EE rider proceeding's North Carolina retail prospective period (April 2012 through July 2012) total, which must be deducted from the test year total, as $5,993,407. He also calculated DEP's North Carolina retail rate period (December 2013 through November 2014) DSM/EE NLR and PPI as $18,058,582.

DEP witness Evans also calculated DEP's total North Carolina retail test year costs and incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI to be $70,351,366. For the prospective period, witness Evans calculated the total to be $17,226,402. He reduced the sum of these figures by $16,635,382, the revenue requirement for the period April 1, 2012, to July 31, 2012, to avoid double counting. Therefore, witness Evans' testimony and exhibits indicated that $70,942,388 is appropriate to use to develop the DSM/EE EMF revenue requirement. Witness Evans' Exhibit 7 showed that the combined test period and prospective period DSM/EE rate billings of $93,368,080 were reduced by prior prospective period billings of $20,093,644, and further adjusted for over- and under-collections of PPI for various programs, as well as for uncollectibles and interest. This resulted in total EMF adjustments of $71,291,616. Therefore, the aggregate DSM/EE over-recovery for purposes of this proceeding is $349,228. This was allocated among customer classes as follows:

Residential	$(1,606,203)
General Service	1,286,113
Lighting	(29,138)
Total EMF Period	$ (349,228)

In his direct testimony, Public Staff witness Maness testified that he had questioned DEP's forecasted rate period O&M costs for the EnergyWise^{SM} program. He said that these costs had increased from about $7.9 million in witness Evans' initial Exhibit 1 to about $11.5 million in Evans' Supplemental Exhibit 1. In response, witness Evans stated in his rebuttal testimony that the Company had agreed to reduce its forecasted rate period O&M costs for the EnergyWise^{SM} program, and that the reduction was reflected in his rebuttal exhibits. Page 5 of Evans Rebuttal Exhibit 1 shows O&M costs for the EnergyWise^{SM} program of $7,854,042, and a total rate period revenue requirement of $75,392,680. Witness Evans testified that this figure included DEP's amortized O&M costs, amortized incremental A&G costs, carrying charges, NLR, and PPI, but excluded gross receipts taxes and regulatory fees.

According to the testimony and exhibits of DEP witness Evans, after allocation to customer classes in accordance with G.S. 62-133.9, Commission Rule R8-69, and the Commission Orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding gross receipts taxes and regulatory fees, are as follows:

Residential	$48,039,813
General Service	26,891,475
Lighting	461,392
Total Rate Period	$75,392,680

DEP witness Evans' Exhibit 3 set forth the North Carolina retail kWh sales for each class that he stated are appropriate to use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding. After subtracting sales to industrial and large commercial customers that have opted-out of DEP's DSM/EE programs, these amounts are as follows: Residential – 15,450,380,543 kWh; General Service – 10,571,063,990 kWh; and Lighting – 433,707,891 kWh.

In DEP witness Evans' rebuttal testimony and his Rebuttal Exhibit 10, he calculated the DSM/EE EMF billing rate for the Residential and Lighting classes to be decrements of 0.010 cents per kWh and 0.007 cents per kWh, respectively, and an increment of 0.012 cents per kWh for the General Service rate class, excluding GRT and the NCRF. Similarly, excluding GRT and the NCRF, he calculated the proposed DSM/EE rider rate to be .297 cents per kWh for Residential customers, .227 cents per kWh for General Service customers, and .101 cents per kWh for Lighting customers. Finally, he also calculated the forward-looking combined DSM/EE and EMF rates for the Residential, General Service, and Lighting classes for the rate period to be increments of 0.297 cents per kWh, 0.247 cents per kWh, and 0.097 cents per kWh, respectively, including GRT and the NCRF.

Public Staff witness Maness indicated that the focus of the Public Staff's investigation of DEP'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. 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. The investigation, including the Public Staff's sampling procedure, was concentrated primarily on costs and incentives related to the April 2012 through March 2013 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 2013 – November 2014) component of the riders. Actual costs and incentives applicable to the rate period, as well as costs and incentives applicable to the April through July 2013 prospective period, which are also included in the DSM/EE EMF riders, will be subject to detailed review in future DSM/EE cost recovery proceedings.

Public Staff witness Maness testified that his investigation of DEP's filing indicated that the Company generally calculated the proposed riders in accordance with the methods set forth in the approved Mechanism for recovery of costs, NLR, and the PPI.

Public Staff witness Floyd also reviewed DEP's allocations of the DSM- and EE-related costs for each customer class. Witness Floyd stated that in his opinion, the Company's allocations in this proceeding are consistent with the Mechanism.

The Commission notes that no party opposed DEP's proposed recovery of NLR and PPI, except for the 2010 vintage of ARP (as discussed previously). The Commission finds that such proposed recovery is consistent with the Commission's Sub 931 Order, as modified by the Commission's November 25, 2009 Order Granting Motions for Reconsideration in Part, in the same docket, and that NLR and PPI are appropriate for recovery in this proceeding, with the prospective and rate period costs subject to further review in DEP's future annual DSM/EE rider proceedings.

Based on the testimony of witness Evans, the testimony of witness Maness, the testimony of witness Floyd, and the entire record in this proceeding, the Commission finds and concludes that the DSM/EE and EMF rates as proposed by DEP in the rebuttal testimony of DEP witness

Evans for the Residential, General Service, and Lighting rate classes, as revised in accordance with Evans Rebuttal Exhibit 10, are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact can be found in the testimony of DEP witness Evans and the testimony of Public Staff witness Floyd.

In the Commission's November 27, 2013 Order in Docket No. E-2, Sub 1019, the Commission ordered DEP to provide information associated with its Solar Water Heating Pilot in its next DSM/EE rider proceeding. In his supplemental testimony filed on August 15, 2013, DEP witness Evans detailed: (1) the costs already recovered; (2) the costs to be recovered in future DSM/EE riders; (3) the A&G and financing costs associated with both; and (4) the number of years remaining to fully recover the costs of the pilot. Witness Evans also testified that the Solar Hot Water Pilot failed the TRC test (was not cost-effective) primarily due to the high cost for program participants to implement the measure relative to its avoided cost benefits.

In his testimony, Public Staff witness Floyd reviewed the information provided by DEP witness Evans and concluded that the costs of the Solar Hot Water Pilot were appropriately included in the test and rate periods. No party disputed these costs. Therefore, the Commission concludes that DEP's costs associated with the Solar Hot Water Pilot are appropriately included in the test and rate periods.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding of fact can be found in the testimony of DEP witness Evans and the testimony of Public Staff witness Floyd.

Public Staff witness Floyd made recommendations regarding future EM&V reports for DEP's ARP and Energy Efficient Lighting programs. In regard to the ARP program, he proposed that future EM&V include the following two items: (1) an assessment of the secondary market and how it is being influenced by the ARP, or alternatively incorporate the findings from other similar evaluations; and (2) incorporation of North Carolina-specific data in determining possible spillover attributed to the program. DEP witness Evans indicated that subsequent to the filing of witness Floyd's testimony, DEP and the Public Staff discussed the use of North Carolina-specific data and mutually agreed that DEP will include Carolinas-specific, both North and South Carolina, data in future ARP EM&V reports.

Concerning the Energy Efficiency Lighting Program, witness Floyd recommended: (1) that future EM&V reports include hours-of-use data for bulbs purchased by non-residential customers that reflect North Carolina-specific installations and usage patterns; and (2) that future intercept surveys of these non-residential participants should include additional questions that attempt to capture the nature of the participant's business, and the likely installation of the bulbs. DEP witness Evans indicated that subsequent to the filing of witness Floyd's testimony, DEP and the Public Staff discussed the use of North Carolina-specific data and mutually agreed that DEP will include Carolinas-specific, both North and South Carolina, data in future Energy Efficient Lighting program EM&V reports.

The Commission finds that the recommendations of Public Staff witness Floyd regarding future EM&V reports for the ARP and Energy Efficient Lighting programs, as modified by the parties' agreement to use Carolinas-specific data, are reasonable, and that DEP should comply with them to the extent that the benefits exceed the costs. If DEP determines that the costs of following any of these recommendations outweigh the benefits, it should discuss the analysis with the Public Staff and, in lieu of complying with a recommendation that costs more than the benefits it provides, include a description of its cost-benefit analysis in the EM&V report.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 18-19

The evidence for these findings of fact is found in the testimony of Public Staff witnesses Maness and Floyd and DEP witnesses Evans and Oliver. In addition, the Commission relies on its June 15, 2009 Order Approving Program in Docket No. E-2, Sub 926 as well as the transcript from that proceeding and the Commission's May 30, 2013 Order Granting General Rate Increase in Docket No. E-2, Sub 1023 (Rate Case Order).

DSDR is an integrated system of electric equipment, operating controls, and a Distribution Management System (DMS) used to control voltage on DEP's distribution grid using real time power flow analysis. DSDR was approved by the Commission as an EE program in Docket No. E-2, Sub 926, and, as such, DEP's current and future DSDR costs are eligible for recovery through the DSM/EE rider.

In its last general rate case (Docket No. E-2, Sub 1023), DEP initially proposed to move DSDR costs out of its DSM/EE rider and into base rates (except those DSDR costs that had been deferred) due to concerns that as the DSDR project moved out of the construction phase it would become more complex and difficult for DEP to identify costs that are attributable to DSDR. Despite these concerns, DEP ultimately withdrew its proposal to move DSDR costs into base rates.

In its Rate Case Order the Commission required DEP to include in this DSM/EE rider proceeding a thorough description of the size and scope of the DSDR accounting issues that prompted DEP's initial proposal to move DSDR cost recovery from the DSM/EE rider into base rates, and the options for addressing those accounting issues.

In his initial testimony in this rider proceeding, DEP witness Evans provided the information that the Commission had required. Specifically, he described three accounting problems related to DSDR costs.

<u>DSDR Accounting Issue No. 1: Distinguishing Between Legacy and DSDR Equipment</u>

DEP witness Evans testified that one DSDR accounting issue involves costs for future replacement and ongoing maintenance of capacitors and regulators that were added to DEP's distribution system as part of the DSDR initiative. Since "distribution capacitors and regulators existed on the system prior to DSDR," DEP's system now includes a mix of legacy equipment and equipment installed for DSDR. Evans testified that as of December 31, 2012, there were 2,400 legacy capacitors and 475 DSDR capacitors on DEP's system. Similarly, as of that date there were 600 legacy regulators and 2,240 DSDR regulators on DEP's system. Evans testified that in order to direct charges for DSDR equipment to DEP's DSM/EE rider, the DSDR equipment (and its costs) must be distinguishable from legacy equipment (and its costs).

Witness Evans presented three options for addressing this accounting problem. He testified that Option 1 would require technicians to physically stencil a "DSDR" label onto capacitors and regulators that DEP installed pursuant to its DSDR program. He estimated that this option would cost $271,500. Witness Evans stated that Option 2 would be to electronically label DSDR equipment in DEP's geographic information system (GIS). He testified that:

> This option does provide clear differentiation; however, appropriately charging to base maintenance or to the DSM/EE Rider will be dependent on employees leveraging technology as opposed [to] a clear visual indicator provided in the field. This option could present a challenge with respect to storm recovery and Supply Chain efforts where access to the records could be limited.

Witness Evans estimated that Option 2 would cost $56,906. Both Option 1 and Option 2 would involve direct charging and both would require enhancements to DEP's distribution work management information system that would allow the system to differentiate between legacy and DSDR-related costs. Evans stated that the cost for these enhancements had not been evaluated.

Witness Evans presented a third option that he called the allocation option. He stated that, under the allocation option, costs would be allocated "between base and DSDR project numbers using a pre-determined ratio." During the evidentiary hearing, when asked how much it would cost to implement the allocation method, witness Evans testified that the costs would be "minimal."

Evans testified that the allocation method is preferable and would provide DEP a method for consistent charging. He stated that Option 1 would be costly to implement, and under Option 2, "the cost ... to update GIS as equipment is moved around the system, in particular during storm restoration, could negate the perceived accuracy of this direct charge methodology."

Witness Maness testified that the Public Staff preferred Option 1 because:

> [i]t is the most direct and least complex of the three methods identified for dividing capacitor and regulator O&M costs between DSDR-related and non-DSDR-related .... In the Public Staff's opinion, the increased precision and reduced complexity of this option is worth the increased cost.

Witness Maness also recommended that in the future, after the initial implementation of the DSDR program, when DEP replaces equipment that has been identified as DSDR-related, the replacement equipment should be identified as "non-DSDR," or as equipment whose costs cannot be included in DEP's DSM/EE program. In his rebuttal testimony, witness Evans disagreed, stating that witness Maness mistakenly assumed that the DSDR program was limited to the initial five-year installation period:

> [T]he DSDR Program, as filed included ongoing costs, and system growth was integral in the determination of the program's cost effectiveness ....

In his rebuttal testimony, witness Evans stated that the Company is willing to adopt Option 1, the direct charge stenciling option, as recommended by the Public Staff.

DSDR Accounting Issue No. 2: Distinguishing Between Incremental DSDR Costs and Non-DSDR Costs for New Load Growth Projects and Recovery of Related O&M Costs

Witness Evans testified that prior to implementing DSDR, DEP's system engineers would estimate the cost for a load growth project, such as a feeder extension, and charge it all to a single work order. With the advent of DSDR, however, load growth projects now "require additional equipment, consisting primarily of regulators and capacitors." Again, to direct the proper charges to the DSM/EE rider, DSDR-related costs must be separated from non-DSDR costs. Witness Evans testified that currently DEP's system engineers determine the incremental portion of new load growth projects that is "incurred due to the DSDR standard," and charge this cost "to a separate project number that directs the costs to the DSM/EE Rider." The remaining costs are recovered in base rates.

To the contrary, Public Staff witness Floyd recommended that the costs of new distribution system expansion projects under the DSDR standard be recovered in DEP's base rates, not in its DSM/EE rider. Witness Floyd asserted that DEP's DSDR program application described DSDR as a finite set of equipment and controls needed to deliver an estimated 247 MW of peak load reduction. He maintained that the application, annual implementation status reports, and other filings in Docket No. E-2, Sub 926 do not indicate any ongoing growth in peak demand savings after project completion. He asserted that DSDR components added after the approved initial installation, which was to occur over a five-year installation period and achieve 247-MW of peak reduction, for the purpose of serving expanded load growth should not be considered to be part of the approved DSM/EE program. Therefore, he recommended that DEP should recover such costs through its base rates, rather than in its DSM/EE rider. He stated that, "the Public Staff believes that once the original scope of the DSDR project to upgrade the distribution system has been completed, that should end the cost recoverable in the DSM rider, except for the O&M expenses related to the original project equipment."

In his rebuttal testimony, DEP witness Evans disagreed with Public Staff witness Floyd. Witness Evans argued that the Company specifically included and recognized prospective system expansion as a part of its application for the approval of DSDR as a DSM/EE program. Witness Evans testified that:

> A DSDR capable distribution system is more costly to construct than a non-DSDR capable distribution system. The Company believes it is appropriate to recover the additional DSDR costs through the DSM/EE rider, because DSDR is an EE program and approved as such by the Commission.

DEP's witness Oliver explained that as DEP's distribution system grows, as new subdivisions are built for example, the Company must design and maintain the new distribution feeders to the DSDR standard in order to maintain the voltage reduction benefit. Witness Oliver explained that the distribution system is dynamic and as it grows the Company must continue to build it to the DSDR standard or else risk losing the current DSDR benefit. In response to

Commission questions, witness Oliver testified that at the time of DEP's DSDR application, it would not have made sense for DEP to have DSDR apply only to the Company's then-existing distribution system, and exclude later expansion of the distribution system from the benefits of DSDR. In addition, witness Oliver reiterated that it would be very difficult to maintain the original benefits of DSDR if future expansion of the Company's distribution system did not include DSDR.

In complying with the Rate Case Order request for full explanation of the accounting issues that had initially prompted DEP to propose moving DSDR costs from the DSM/EE rider to base rates, DEP also brought forth the issue of cost recovery for ongoing maintenance, repair and replacement related to expansion of the DSDR portion of the distribution system. DEP's witness Oliver's testimony indicated that beyond continuing O&M expenses for DSDR assets that are part of the initial implementation expected to be completed in 2014, the Company will also continue to incur costs related to its DSDR distribution expansion assets, including replacement and repair of DSDR equipment. The Company's position is that these DSDR expansion-related costs should be recoverable in the DSM/EE rider.

During the evidentiary hearing witness Maness clarified the Public Staff's position as follows:

> If the operation and maintenance expense is related to that original footprint of DSDR, which would be identified through the stenciling procedure that we've recommended, then that operation and maintenance expense would continue to be recovered through the rider.

Thus, the Public Staff's position appears to be that if maintenance and replacement costs are related to DSDR equipment that was installed as part of the initial implementation of DSDR (expected to be complete in 2014), those costs could be recovered in the rider. But if the expenses are related to new DSDR installation or expansion beyond the 2014 completion, they could not be recovered through the rider.

<u>DSDR Accounting Issue No. 3: Separating Depreciation of DSDR Assets From Depreciation of Non-DSDR Assets</u>

DEP witness Evans testified that:

> DEP calculates depreciation based on the group depreciation method. DSDR assets are part of depreciation groups that include non-DSDR assets. As a result, depreciation for DSDR assets is calculated manually based on the DSDR asset base and group depreciation rate. This has to be done outside of the Company's fixed asset system. This calculation is complex and time consuming due to the volume of transactions and assets involved. Even with the manual depreciation calculation, the assets are not tracked individually and are accumulated by FERC plant account. As assets are not tracked individually, this makes it complex to identify if assets are fully depreciated.

During the evidentiary hearing, witness Evans was asked whether it would be possible to "simply create a separate asset group or groups for DSDR assets." He replied that this concept, "could very easily be at least considered, if not accommodated."

DEP's witness Evans testified that DEP's proposal for handling the DSDR administrative and accounting issues is as follows:

> (1) Directly charge to the DSM/EE rider those DSDR costs that can be clearly identified, including incremental labor costs, telecommunications and technology maintenance fees.
>
> (2) For capacitors and regulators, allocate the repair and replacement costs to the DSM/EE rider based on the number of units that were added as part of the DSDR project.
>
> (3) For distribution growth projects, estimate the incremental portion of the cost related to the DSDR standard and charge the incremental cost to the DSM/EE rider and the remainder to base rates.
>
> (4) Continue to maintain a manual tracking system for the depreciation and net plant balances for DSDR property outside of DEP's normal property accounting system.

DEP witness Oliver testified that DSDR's total system capability would be available to help meet summer peak loads in 2014.

<u>Discussion and Conclusions</u>

While the Commission's Order in E-2, Sub 926 approving DSDR as an EE program did not directly address whether the DSDR program should be approved as a five-year program or as an ongoing program, the Commission will address the issue now due to unique factual aspects of DSDR and their implications. In approving DSDR as an EE program, the Commission understood that some of the costs involved were for components and activities that are essentially identical to those found in traditional electric utility operations. The Commission was also aware that DSDR would require on-going O&M and capital investments.[1] All witnesses agreed, and the Commission finds, that from this time forward it is prudent and appropriate for DEP to design and build all system growth and expansion projects in a manner that is consistent with DSDR and capable of contributing to DSDR's energy and capacity savings. Witnesses testified that DSDR's energy and capacity savings are expected to grow over time as customer load grows. The Commission, therefore, concludes that, so long as DSDR remains cost effective and qualifies as an EE program, it is in the public interest to allow DSDR costs to continue to be recovered through the DSM/EE rider. It is appropriate for DEP to recover costs incurred to maintain and expand the DSDR program and its benefits on DEP's distribution system through the DSM/EE rider.

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[1] See testimony of DEP witness Robert Simpson on page 65 of Volume 1 of the transcript in Docket No. E-2, Subs 926 and 931 dated January 7, 2009.

The Commission's decision regarding the continuation of DSDR cost recovery through the DSM/EE rider is limited to the unique facts of the DSDR program as approved in E-2, Sub 926. The DSDR program was approved by the Commission as an EE program without discussion or direction as to the cost recovery issues brought to the Commission's attention by DEP in this proceeding in compliance with the Rate Case Order. The complexity of these issues was not clear to the Commission until DEP began working on DSDR and started assigning various costs to be recovered under the rider. Therefore, the Commission finds that the circumstances which created the above-discussed accounting issues are unique and applicable only to the DSDR program as approved in E-2, Sub 926. Accordingly, this decision on cost recovery for DSDR shall not be considered or cited as precedent for any future programs or issues that come before the Commission.

In order to monitor DSDR's continued cost-effectiveness and qualification as an EE program on an ongoing basis, the Commission will require DEP to report the actual energy savings (annually and cumulatively), and capacity savings achieved by DSDR in the annual report that it files in Docket No. E-2, Sub 926. The Company shall also annually file 10-year budget and energy and capacity savings forecasts for DSDR in its DSDR annual report. Finally, in order to facilitate review of DSDR's cost-effectiveness, beginning in 2014, DEP shall file its annual report for DSDR in Docket No. E-2, Sub 926 at the same time that it files its annual DSM/EE rider application.

Although DEP currently expects DSDR will be fully implemented by the summer of 2014, it is clear there will be cost recovery items related to DSDR that continue beyond the initial installation and implementation of DSDR as approved. It is also clear from the testimony of DEP witness Evans that some categories of on-going DSDR costs will require additional work processes for system engineers and field personnel, as well as for DEP's accountants. He also testified that, because the Commission has found that DSDR is a new EE program, the Company is entitled to have incremental costs of DSDR recovered in its DSM/EE rider. No party disputed DEP's position in this regard.

The Commission finds that some of the accounting processes that witness Evans discussed for handling DSDR costs will be inefficient and could ultimately increase costs to customers. One example is DEP's acquiescence to the option of spending $271,500 stenciling "DSDR" on capacitors and regulators simply to encourage (but not guarantee) field personnel will charge on-going O&M and replacement costs related to the traditional distribution system for recovery through base rates rather than through the DSM/EE rider. The Commission concludes this stenciling process is inefficient and would result in unnecessary costs. Another example involves determining the incremental costs for new load growth projects. DEP's proposed process would require system engineers to estimate the costs of a feeder both with and without DSDR capability in order to assign the DSDR increment to the DSM/EE rider for recovery. The Commission concludes this cumbersome process would unnecessarily add significant DSDR costs to be recovered from ratepayers. Therefore, the Commission will allow DEP to pursue witness Evans' four-point proposal for addressing DSDR's accounting issues and recovering DSDR costs through the DSM/EE rider, with two exceptions noted below.

First, instead of stenciling capacitors and regulators, DEP shall develop and implement allocation ratios that will result in an appropriate portion of its capacitor and regulator O&M and replacement costs being charged to the DSM/EE rider. In conjunction with its next DSM/EE rider application, the Company shall file (and the Public Staff is requested to review) worksheets explaining the development and implementation of those allocation ratios, with the implementation to begin with the rate period that starts December 1, 2014.

Second, instead of DEP's distribution system planners being required to develop cost estimates for each expansion project with and without DSDR capability in order to allocate the incremental DSDR costs to the DSM/EE rider, the Commission hereby requires DEP to develop a methodology for estimating the DSDR portion of system expansion costs and allocating those costs on a percentage basis to the DSM/EE rider. DEP shall file its proposed methodology for review in its next rider application for use beginning with the rate period that starts December 1, 2014.

Regarding the third DSDR accounting issue involving the depreciation of DSDR assets, the Commission will require DEP to evaluate whether creating a separate DSDR asset group(s) would better address the problems identified by witness Evans. DEP shall include that evaluation in its next DSM/EE rider application.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact is found in the testimony of DEP witnesses Evans and Oliver and Public Staff witness Maness.

In its May 30, 2013 Rate Order, the Commission noted that DEP's DSDR application in Docket No. E-2, Sub 926 stated that DSDR would be complete in 2012, but that more recent Company submittals and testimony showed full implementation would not be complete until 2014. The Commission questioned whether the NLR incentive for DSDR is appropriate given that DEP had failed to fully implement DSDR in time to serve customers during the summer of 2013. The Order required DEP to "explain in its upcoming DSM/EE rider application whether and why it is still appropriate for the Company to recover from customers the NLR incentive."

In his pre-filed direct testimony, witness Evans stated that a disallowance of NLR for DSDR would "provide a tangible financial disincentive to the Company" for DSDR activations. During questioning by the Commission, he clarified that in situations where the Company really needed DSDR, "it would be run. ... [T]here's just too much at stake to make certain that we provide customer benefits."

In his pre-filed direct testimony, Evans stated that DEP does not believe a disallowance of NLR for DSDR would be consistent with Commission Rule R8-68(b)(5) and (c)(3)v, or with the Mechanism. He noted that the Commission had approved the NLR incentive for DSDR in Docket No. E-2, Sub 931. He also testified that DEP is not requesting any NLR for DSDR in this proceeding.

Witness Maness testified that, on the basis of witness Evans' testimony and the Public Staff's monitoring of the DSDR project, "the Public Staff does not recommend that any DSDR NLR recovery be disallowed at this time."

DEP does not seek any NLR for DSDR in this proceeding. Therefore, the Commission finds that it is not necessary to rule on this issue at this time. Rather, the Commission will wait until DEP proposes to recover NLR for DSDR and more information is available regarding the program's actual performance, including the date on which it is fully implemented, to consider whether and why it is still appropriate for the Company to recover from its customers any NLR associated with DSDR.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding of fact can be found in the testimony of DEP witness Evans, the testimony of SACE witness Mims, the testimony of Public Staff witness Floyd, and the post-hearing letter filed by NCSEA.

SACE witness Mims recommended that DEP: (1) aim to achieve greater energy savings; (2) investigate whether it can make the Neighborhood Energy Saver program cost effective; (3) investigate additional EE programs to enable it to achieve savings equal to 1 percent of retail sales; (4) present key EM&V data by program in an annual summary document; and (5) initiate quarterly collaborative meetings similar to those held by DEC. She also testified that DEP has an opt-out rate (by large commercial and industrial customers) that is approximately 30 percent of its sales. Witness Mims recommended that DEP pursue new programs that would appeal to the kinds of customers that have opted-out, including a direct install program for government and non-profit customers, and programs targeting campuses and grocery stores. Similarly, she cited six specific programs targeting residential and small commercial customers that are currently being implemented by organizations in other states. She suggested that DEP consider implementing similar programs. Witness Mims made numerous suggestions for improvements to DEP's existing programs as well. She advocated that DEP pursue all cost-effective EE and DSM.

DEP witness Evans testified that DEP is willing to establish a collaborative, and that such a collaborative is the appropriate forum in which to discuss modifications to existing programs or proposals for new programs. Similarly, witness Floyd testified that the Public Staff supported establishment of a collaborative. Counsel for DEP also stated on the record that DEP plans to have the collaborative consider and develop a position regarding either a limited study or survey of customers who have opted-out of its DSM/EE programs and report the results and any conclusions or recommendations as part of its 2014 DSM/EE rider filing.

In its letter filed in lieu of a post-hearing brief, NCSEA stated that it supported the establishment of a collaborative and DEP's plans to have the collaborative consider how best to study or survey DEP's opt-out customers.

Based on the testimony, counsel's representation, and the letter cited above, the Commission concludes that DEP should establish an EE collaborative that will, among other things, consider a limited study or survey of opt-out customers. In addition, the Commission strongly encourages the collaborative to consider the specific program recommendations provided by witness Mims, and whether DEP could successfully implement such programs in its service territory. Finally, the Commission agrees with witness Mims that the Company could present key EM&V data in a more useful fashion and encourages the Company to review, and if possible adopt, DEC's approach in this regard.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence for this finding of fact is found in the testimony of DEP witness Evans. In addition, the Commission references DEP's annual filing in Docket No. E-100, Sub 10A, which the Company cited in its October 11, 2013, late-filed exhibit.

In response to questions from counsel for NCSEA, witness Evans expressed reservations about NCSEA's proposal to require the Company to inform all customers of the forecasted summer peak demand so that customers could engage in voluntary demand response and peak shaving. He testified that while the Company provides customers with efficiency tips, "in terms of asking customers to actively lower their usage, that is a situation often of last resort." He testified that when such a request is made of the public, there are ramifications in terms of those government entities that regulate electric system reliability, such as NERC[1] and SERC[2].

In its October 11, 2013 late-filed exhibit, DEP referred to the General Load Reduction & System Restoration Plan that it filed May 13, 2013, in Docket No. E-100, Sub 10A. That document describes levels of reliability including "Reliability Level 2 – Load Management and General Customer Appeal." According to the Plan, Reliability Level 2 is characterized by a situation in which "the projected customer load and reserve requirements are marginally greater than the available capacity." At this level, the Company would issue a news release appealing to the public to voluntarily reduce use of electricity.

Based on the testimony of witness Evans, as well as DEP's General Load Reduction & System Restoration Plan cited above, the Commission finds that it is possible that requiring DEP to pursue a program such as the one suggested by NCSEA would potentially reduce the effectiveness of public appeals that might be needed due to emergency conditions. Therefore, the Commission concludes that it is not appropriate at this time to require DEP to develop a GEA program designed to notify customers of anticipated system peaks and urge them to refrain from using electricity during such peaks. Rather, DEP should discuss NCSEA's proposal with the collaborative described above and explore whether and how such a program could be designed without potentially conflicting with the Company's plans for handling system emergencies.

[1] North American Electric Reliability Corporation.

[2] SERC Reliability Corporation.

IT IS, THEREFORE ORDERED, as follows:

1. That the appropriate DSM/EE EMF billing factors to be charged by DEP during the rate period are increments or decrements as follows:

Rate Class	DSM/EE EMF (Excluding GRT and NCRF)	DSM/EE EMF (Including GRT and NCRF)
Residential	(0.010) cents per kWh	(0.010) cents per kWh
General Service	0.012 cents per kWh	0.012 cents per kWh
Lighting	(0.007) cents per kWh	(0.007) cents per kWh

2. That the appropriate forward-looking DSM/EE rates to be charge by DEP during the rate period are increments as follows:

Rate Class	DSM/EE Rate (Excluding GRT and NCRF)	DSM/EE Rate (Including GRT and NCRF)
Residential	0.297 cents per kWh	0.307 cents per kWh
General Service	0.227 cents per kWh	0.235 cents per kWh
Lighting	0.101 cents per kWh	0.104 cents per kWh

3. That the appropriate total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF (including GRT and the NCRF) are increments as follows:

Rate Class	Total DSM/EE Rider
Residential	0.297 cents per kWh
General Service	0.247 cents per kWh
Lighting	0.097 cents per kWh

4. That in its next DSM/EE rider application DEP shall recalculate the PPI and NLR associated with the 2010 vintage of ARP based on the new protocol.

5. That DEP shall incorporate the recommendations of Public Staff witness Floyd regarding future EM&V reports for the Energy Efficient Lighting Program and ARP, as modified by the agreement of the parties as to using Carolinas-specific data, to the extent that the benefits exceed the costs. If the costs of following a recommendation outweigh the benefits, DEP shall discuss its analysis with the Public Staff and include a description of the analysis in the EM&V report.

6. That DEP shall file in its next DSM/EE rider application detailed worksheets explaining the development and implementation of the allocation ratios that it will use to allocate to the DSM/EE rider costs for the repair and replacement of DSDR equipment that cannot be clearly identified and wholly charged to DSDR.

7. That DEP shall file in its next DSM/EE rider application an allocation method determining which portion of distribution expansion costs shall be recovered under base rates as

non-DSDR related costs and which portion shall be recovered in the DSM/EE rider as DSDR-related costs.

8. That DEP shall include additional information as discussed herein in all future DSDR annual reports, and shall file each year's report when it files its annual DSM/EE rider application.

9. That DEP shall establish a collaborative similar to the one in place for DEC and have the collaborative consider and develop positions regarding: (1) either a limited study or survey of customers who have opted-out of its DSM/EE programs and report the results and any conclusions or recommendations as part of its 2014 DSM/EE rider filing; (2) new programs and program modifications as recommended by SACE; and (3) whether DEP should be required to notify customers regarding forecasted peaks in order to encourage them to reduce energy use.

ISSUED BY ORDER OF THE COMMISSION.
This the _23rd_ day of January, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. E-2, SUB 1030

CHAIRMAN EDWARD S. FINLEY, JR., CONCURRING IN RESULT: By the conclusion of the evidentiary hearing, the Distribution System Demand Response (DSDR) issue left unresolved between Duke Energy Progress, Inc. (DEP), and the Public Staff concerned the appropriate vehicle for the recovery of costs for DSDR facilities installed for future expansion of the distribution system, or DSDR costs incurred after retrofitting the existing distribution system. Most of the DEP and Public Staff testimony in this docket addressed the Commission's intent when it approved DSDR in Docket No. E-2, Sub 926 in 2009, rather than whether it is appropriate to treat DSDR costs for the expanded distribution system as a continuation of the previously-approved energy efficiency (EE) measure eligible for treatment under Senate Bill 3 (G.S. 62-133.9), irrespective of the intent expressed in Docket No. E-2, Sub 926.

In my view, what the parties and the Commission intended in Docket No. E-2, Sub 926 is of less consequence than whether DSDR expansion costs are appropriately recovered through the demand-side management and energy efficiency (DSM/EE) rider or base rates. That decision should be based on what the expansion of the DSDR measure actually does. Quite frankly, the Commission's focus in Docket No E-2, Sub 926 was not specifically on DSDR costs for future expansion of the distribution system, even though it is difficult to conceive that DSDR operates as intended when installed only on less than all of the distribution circuits. The issues that captured most of the Commission's attention were whether DSDR was demand-side management (DSM) as opposed to an EE measure and whether industrial and large commercial customers' opt out decisions pursuant to G.S. 62-133.9(f) should apply to DSDR costs.

The General Assembly, in Senate Bill 3, determined that new (post-January 1, 2007) DSM or EE measures should receive treatment different from costs for traditional measures. The electric utility should be entitled to receive incentives for implementing new DSM and EE measures, and cost recovery for the measures should be accomplished through an annual rider, not base rates. G.S. 62-133.9(d). Industrial and large commercial customers are entitled to opt out if they employ their own DSM/EE measures. DSDR has been determined to be a new EE measure, although it has unique features in that the measure operates on the company's side of the meters and consumers have no ability to opt in or out of the benefits of the measure. The purpose and benefit of DSDR is that it reduces demand on peak by reducing system-wide voltage and, therefore, eliminates or reduces the need to build expensive new production plants. The Public Staff did not argue in Docket No. E-2, Sub 926 that DSDR failed to meet the criteria for DSM/EE cost recovery or that the measure was not a cost-beneficial DSM/EE measure. The costs avoided by DSDR should more than offset the costs of installing and maintaining DSDR, plus the incentives paid. Evaluation, measurement, and verification (EM&V) analyses and reports must be used to ensure that this cost/benefit trade-off really occurs and continues.

As stipulated by DEP and approved in Docket No E-2, Sub 931, DEP's cost-recovery mechanism precludes the recovery of a program performance incentive (PPI) for DSDR. Recovery of net lost revenues can only occur, where proven to exist and where not offset by net gained revenues, for a limited period of time and is cut off by general rate cases. As of yet DEP has not sought net lost revenues associated with DSDR. No dispute exists in this docket that, unless otherwise excessive or imprudently spent (e.g., gold-plated), the DSDR costs are reasonable and prudent. DSDR costs for expanded distribution facilities will be substantially lower than the retrofit costs from the initial phase and will be spread out over a far longer time. Therefore, over the long term, whether the costs are recovered through base rates or through the DSM/EE rider should not have a significant impact on the overall cost of service.[1] The primary difference, then, is from whom the costs of implementing DSDR on the expanded distribution system should be recovered. If DSDR costs are recovered through the rider, qualifying industrial and large commercial customers escape cost responsibility and the remaining customers bear more of these costs. This result is the most significant impact on consumers from the Commission's decision on this issue. Were the Commission free to change this result, perhaps it would. But, as previously determined, the General Assembly has not left the Commission free to make this choice, and, as a consequence, it should not be a factor in assessing whether DSDR costs should be recovered through the rider or base rates.

Regarding the merits of DSDR cost recovery, whether through the DSM/EE rider or base rates, the Public Staff argues that after installation of DSDR facilities in the initial phase DSDR becomes a new baseline, or an essential and required part of the distribution system, and, therefore, the costs should be recovered through base rates. While I agree that DSDR, as long as its benefits continue to exceed costs, should continue to be a required feature of the expanded distribution system, to me, it does not follow that this fact determines the manner of cost recovery. The DSDR program was first adopted after 2007 and was determined to be a new EE measure eligible for Senate Bill 3 EE cost recovery. Although for now an essential part of expanded distribution system

[1] Costs recovered through a DSM/EE annual rider are recovered dollar for dollar and are trued up through an experience modification factor, so they are not offset by other cost decreases that might be considered in a general rate case.

installation, it still is the continuation of a measure eligible for Senate Bill 3 cost recovery treatment as a new EE measure because it meets the statutory criteria, it reduces demand, and it reduces production plant costs. In addition, it reduces harmful emissions. Of all the measures for which Senate Bill 3 provides incentives and statutory promotion, EE and DSM programs are the most beneficial to customers because they have the greatest potential to reduce rates.

The alternative to viewing DSDR on expanded distribution as a continuation of the existing measure would be to treat DSDR for the expanded distribution as another new DSM/EE measure. Still, in my view, it would qualify for DSM/EE cost recovery because it would meet the test as an even newer measure. Whether it continues to qualify in the future will depend on whether the EM&V examination shows that the benefits exceed the costs and not on whether a new baseline has been established.

/s/ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

DOCKET NO. E-2, SUB 1043

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Application by Duke Energy Progress, Inc.,	)	
for Approval of Renewable Energy and Energy	)	ORDER APPROVING REPS AND
Efficiency Portfolio Standard Cost Recovery	)	REPS EMF RIDERS AND 2013 REPS
Rider Pursuant to G.S. 62-133.8 and	)	COMPLIANCE
Commission Rule R8-67	)	

HEARD: Tuesday, September 16, 2014, at 10:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Progress, Inc.:

Charles A. Castle, Associate General Counsel, Duke Energy Corporation, 550 South Tryon St., Charlotte, North Carolina 28202

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the North Carolina Sustainable Energy Association:

Michael Youth, North Carolina Sustainable Energy Association, 4800 Six Forks Rd., Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, L.L.P., 4010 Barrett Drive, Suite 210 Raleigh, North Carolina 27609

BY THE COMMISSION: On June 23, 2014, Duke Energy Progress, Inc. (DEP or the Company), filed its annual Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Compliance Report and Application (Application) seeking an adjustment to its North Carolina retail rates and charges pursuant to G.S. 62-133.8(h) and Commission Rule R8-67. These provisions require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of G.S. 62-133.8(b), (d), (e) and (f) and to true-up any under-recovery or over-recovery of compliance costs. DEP's Application was accompanied by the testimony and exhibits of Jonathan L. Byrd, Renewable Strategy and Compliance Manager, and Veronica I. Williams, Rates Manager. In its Application and pre-filed testimony, DEP sought approval of the proposed REPS rider, which incorporated the Company's proposed adjustments in its North Carolina retail rates.

On July 2, 2014, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEP rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines. DEP subsequently published notice in newspapers of general circulation, as required by the Order, and filed proof of publication on September 11, 2014.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) and Carolina Utility Customers Association, Inc. (CUCA). These petitions were granted by the Commission on July 1, 2014, and July 8, 2014, respectively. The intervention and participation by the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On August 28, 2014, DEP filed the supplemental testimony and revised exhibits of witnesses Byrd and Williams. On September 3, 2014, DEP filed the revised supplemental testimony of witness Williams and second revised Williams Exhibit No. 4. On September 4, 2014, the Public Staff filed the affidavits of Jay B. Lucas, Electric Engineer – Electric Division, and Michelle M. Boswell, Staff Accountant – Accounting Division.

The matter came on for hearing as scheduled on September 16, 2014. DEP presented the testimony and exhibits of witnesses Byrd and Williams, and the Public Staff presented the affidavits of witnesses Lucas and Boswell. No other party presented witnesses, and no public witnesses appeared at the hearing.

On October 31, 2014, the Public Staff and DEP filed a joint proposed order.

On November 13, 2014, NCSEA filed a notice of change of address; NCSEA's new address is as stated on page 1 of this Order.

Based upon the foregoing, DEP's verified Application, the testimony and exhibits received into evidence at the hearing, the records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

13. DEP is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.8 and Commission Rule R8-67.

14. General Statute 62-133.8(h) authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in G.S. 62-133.8(h)(1), include the reasonable and prudent costs incurred by an electric power supplier to comply with REPS "that are in excess of the electric power supplier's avoided costs." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

15. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs. The test period for this proceeding is the 12 months from April 1, 2013, through March 31, 2014. The billing period is the 12 months beginning on December 1, 2014, and ending on November 30, 2015.

16. DEP has agreed to provide REPS compliance services, including the procurement of RECs, to the following wholesale electric power suppliers (Wholesale Customers): the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, the Town of Winterville and the City of Waynesville.

17. DEP has complied with the 2013 general requirement and solar set-aside requirement for itself and the Wholesale Customers for which the Company is providing compliance services. Pursuant to the Commission's Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief in Docket No. E-100, Sub 113, issued on

March 26, 2014 (2013 Relief Order), the Commission eliminated the 2013 swine waste set-aside requirement and delayed for one year the poultry waste set-aside requirement.

18. DEP has appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and billing period. For purposes of establishing the REPS Experience Modification Factor (EMF) rider in this proceeding, DEP's incremental costs for REPS compliance during the test period were $22,088,610, with $21,947,243 correctly allocated to retail customers. These costs were reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period total $23,830,790, with $23,678,274 correctly allocated to retail customers. It is appropriate to reduce this amount by $140,993, resulting in an adjusted billing period incremental cost of $23,537,281 for DEP's retail customers.

19. DEP's under-recovery of incremental costs amounts to $2,051,856 for the EMF period, April 2013 through March 2014.

20. The appropriate monthly amount of the REPS EMF rider per customer account excluding the regulatory fee to be collected during the billing period is ($0.05) for residential accounts, $1.16 for general service accounts, and $6.91 for industrial accounts.

21. The appropriate monthly amount of the REPS rider per customer account excluding the regulatory fee to be collected during the billing period is $0.88 for residential accounts, $4.94 for general service accounts, and $17.62 for industrial accounts.

10. The combined monthly REPS and REPS EMF rider charges per customer account excluding the regulatory fee to be collected during the billing period are $0.83 for residential accounts, $6.10 for general service accounts, and $24.53 for industrial accounts.

11. DEP's combined REPS and REPS EMF riders to be charged to each customer account for the billing period are within the annual cost caps established in G.S. 62-133.8(h)(4).

12. The costs of the research activities funded by DEP during the test period and planned for the billing period are reasonable and prudent and within the statutory $1-million annual limit, and, therefore, are recoverable pursuant to G.S. 62-133.8(h)(1)(b). It is appropriate for DEP to provide, in its 2015 REPS rider application, the results of its REPS-related research when these results are publicly available, and the procedures for third parties to access the results when they are proprietary. For research projects sponsored by the Electric Power Research Institute (EPRI), DEP should provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary.

13. In some of its REC purchase contracts, DEP has required its REC suppliers to provide environmental attributes that are not included in the statutory definition of a REC in G.S. 62-133.8(a)(6). These contract provisions are not prohibited. However, costs associated with DEP's purchase of environmental attributes included in RECs could be disallowed in future cost

recovery proceedings upon a finding that such recovery from DEP's North Carolina retail customers is not appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

These findings of fact are essentially informational, procedural, and jurisdictional in nature and are uncontroverted. The evidence for these findings of fact can be found in DEP's Application, the requirements of G.S. 62-133.8 and Commission Rule R8-67.

General Statute 62-133.8(h)(4) requires the Commission to allow an electric utility to recover through an annual rider all of its incremental, reasonable, and prudent costs incurred to comply with G.S. 62-133.8. G.S. 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs, other than those costs recovered pursuant to G.S. 62-133.9.

Commission Rule R8-67(e)(1) provides that the Commission shall schedule an annual public hearing to review an electric utility's REPS compliance costs. Subdivision (e)(3) of Rule R8-67 further provides that the test period for each utility shall be the same as the test period for purposes of Rule R8-55. Rule R8-55 provides that DEP's test period is the twelve months ending March 31 of each year. Therefore, DEP proposed a test period for its REPS cost recovery proceeding of the twelve months ending March 31, 2014.

Rule R8-67(e)(4) provides that the REPS and REPS EMF riders shall be in effect for a fixed period, which "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel charge adjustment proceeding, Docket No. E-2, Sub 1045, and in this proceeding, DEP proposed, without objection from any party, that its rate adjustments take effect on December 1, 2014, and remain in effect for a 12-month period. This period is referred to herein as the "billing period."

The test and billing periods proposed by DEP were not challenged by any party. The Commission concludes that the test period appropriate for use in this proceeding is the twelve months ending March 31, 2014, and the appropriate billing period is the twelve months ending November 30, 2015.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for these findings can be found in DEP's Application, the direct testimony and exhibits of DEP witness Byrd, the testimony and affidavit of Public Staff witness Lucas and the requirements of G.S. 62-133.8. The Commission also takes judicial notice of information in NC-RETS pertaining to DEP's retirement of RECs.

DEP witness Byrd described in his testimony the Company's efforts to comply with the REPS requirements, and he discussed these efforts more fully in the REPS compliance report, which was admitted into evidence as Byrd Exhibit No. 1. Witness Byrd testified that the report provided the information required by Commission Rule R8-67(c) in the aggregate for DEP and the

Wholesale Customers for which DEP has agreed to provide REPS compliance services. He further stated that the Company began providing REPS compliance services to the Town of Winterville, effective January 1, 2013, and that the current REPS rider reflects the addition of Winterville for cost allocation purposes, in addition to the credit related to the Town of Winterville's buy-in for its component share of the Company's REC inventory. He also testified that DEP continues to provide REPS compliance services for five other wholesale electric customers, which are also electric power suppliers: the Town of Sharpsburg, the Town of Stantonsburg, the Town of Lucama, the Town of Black Creek, and the City of Waynesville. No party took issue with DEP's purchase of RECs for the Wholesale Customers.

Witness Byrd testified that, for calendar year 2013, the Company must generally supply an amount of at least 3 percent of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures. He stated that as part of the Total Requirement, the Company must supply energy in the amount of at least 0.07 percent of the previous year's North Carolina retail sales from solar resources (the Solar Set-Aside). He explained that in 2014, these percentages required for compliance remain the same, but that in 2015, the Total Requirement will increase to 6 percent, and the Solar Set-Aside will increase to 0.14 percent of the previous year's North Carolina retail sales. Beginning in 2012, G.S. 62-133.8(e) and (f) require DEP and other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from swine and poultry waste resources (referred to as the Swine Set-Aside and the Poultry Set-Aside, respectively). However, in its 2013 Relief Order, the Commission eliminated the Swine Set-Aside for 2013, and delayed for one year the Poultry Set-Aside requirements for DEP and other electric suppliers. In 2014, the Company must supply energy in the amount of its pro-rata share of at least 0.07 percent of the previous year's total statewide aggregate retail sales to meet the Swine Set-Aside, and energy in the amount of its pro-rata share of 170,000 megawatt-hours (MWh) to meet the Poultry Set-Aside.

DEP witness Byrd testified that the Company's general REPS requirement for 2013, based on 3 percent of the total of DEP's 2012 retail sales (36,589,397 MWh) and those of it Wholesale customers (194,877 MWh) is 1,103,531 total RECs, including 25,752 solar RECs.

Witness Byrd testified that the Company has submitted for retirement 1,103,531 RECs, including 25,752 RECs to meet the Solar Set-Aside requirement for calendar year 2013. The RECs to be used for 2013 compliance have been transferred from the NC-RETS Progress Energy Electric Power Supplier account to the Progress Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale Customers. Witness Byrd's testimony is consistent with the records in NC-RETS.

During the prospective billing period, which spans parts of two calendar years, with different requirements in each year, witness Byrd stated that the Company's estimated obligations are as follows: in 2014, the Company estimates that it will be required to submit for retirement 1,116,510 RECs to meet its Total Requirement. Within this total, the Company is also required to retire the following: 26,052 solar RECs, 26,052 swine RECs, and 47,474 poultry RECs. In 2015, the Company estimates that it will be required to submit for retirement 2,263,365 RECs to meet its General Requirement. Within this total, the Company estimates that will be required to retire approximately 52,812 solar RECs, 26,406 swine RECs, and 197,329 poultry RECs. Witness Byrd stated that the Company is well-positioned to comply with its Solar Set-Aside, Poultry Set-Aside, and Total Obligation requirements in 2014; however, it projects that it will not meet its Swine Waste Set-Aside requirement in 2014.

Public Staff witness Lucas testified that DEP has met the compliance requirements for 2013 by placing a sufficient number of general and solar RECs in the NC-RETS compliance sub-accounts of itself and the Wholesale Customers. He also stated that the Public Staff has reviewed DEP's REPS compliance report for 2013 and recommends that the Commission approve it for DEP and the Wholesale Customers.

Based on the evidence presented, the information in NC-RETS, and the record as a whole, the Commission finds and concludes that DEP and the Wholesale Customers for which it is providing REPS compliance services have complied with the REPS requirements for 2013, and that DEP's 2013 REPS compliance report should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-11

The evidence supporting these findings of fact appears in DEP’s Application, the testimony and exhibits of DEP witness Byrd, the testimony and revised exhibits of DEP witness Williams, the testimony and affidavit of Public Staff witness Lucas, and the affidavit of Public Staff witness Boswell.

Witness Williams testified that DEP calculated its incremental costs associated with its purchases from renewable energy facilities, such that for each contract with a renewable energy facility where DEP is purchasing bundled energy and RECs, the Company calculated the applicable avoided cost over the term of the contract. This avoided cost was then subtracted from the total cost associated with the renewable energy purchase to arrive at the incremental cost for that renewable energy purchase during the period in question. The costs associated with unbundled REC purchases are completely incremental and are included directly in the calculation of rates.

DEP witness Byrd testified that besides the costs of purchases of renewable power and RECs, DEP seeks to recover costs associated with the support of various research and development efforts and studies, internal labor costs associated with REPS compliance activities, and non-labor costs associated with administration of REPS compliance. Among the non-labor costs associated with REPS are the Company’s subscription to the NC-RETS and an external REC accounting system.

For purposes of cost allocation, DEP witness Williams testified that incremental costs assigned to DEP retail customers are separated into two categories: costs related to solar, poultry and swine compliance requirements, and research and other incremental costs Set-Aside and Other Incremental Costs; and costs related to the General Requirement (General Incremental Costs). This separation is calculated in Williams Exhibit No. 1.

She further stated that Set-Aside and Other Incremental Costs are allocated among customer classes based on the per-account cost caps. General Incremental Costs are allocated among customer classes in a manner that gives credit for energy efficiency (EE) RECs (for which there are no General Incremental Costs) according to the relative energy reduction contributed by each customer class. As a result, witness Williams testified that General Incremental Costs are allocated among customer classes based on each class's pro-rata share of requirements for non-EE general RECs. This method of cost allocation is applicable to both the EMF and billing period costs. Witness Williams explained that, in the future, should this method result in an allocation of costs to a particular class in excess of the per-account cost cap for that class, the excess over the respective cap for that class will be re-allocated proportionally to the remaining classes.

Witness Williams' revised exhibits show that DEP's incremental costs of retail REPS compliance were $21,947,243 for the EMF period. Her revised exhibits also show a $2,051,856 net under-recovery of incremental costs for the EMF period. The forecasted incremental costs for retail REPS compliance for the billing period, as revised through Williams' revised and second revised exhibits, amounted to a total of $23,678,274. In the supplemental filing of September 3, 2014, DEP made corrections to its EMF calculations that increased its requested EMF costs. In order to keep the total REPS rates at the amounts listed in the public notice, DEP decreased its proposed forecasted incremental costs by $140,993, to $23,537,281. The Public Staff agreed with DEP's proposed EMF and forecast of incremental costs.

Witness Williams, based on her revised exhibits and second revised Exhibit No. 4 calculated the monthly REPS rider amounts of $0.88 for the residential class, $4.94 for the general service class, and $17.62 for the industrial class. She also calculated the monthly REPS EMF rider amounts of ($0.05) for the residential class, $1.16 for the general service class, and $6.91 for the industrial class. Thus, the combined monthly REPS and REPS EMF rates are $0.83 for the residential class, $6.10 for the general service class and $24.53 for the industrial class, not including the regulatory fee.

Public Staff witnesses Lucas and Boswell testified that they reviewed and analyzed the REPS incremental costs for which DEP had requested recovery in this proceeding, found them to be appropriate, and recommended their approval. No other party presented any evidence regarding DEP's REPS incremental costs. Witness Lucas further testified that the Public Staff believed that the costs to be recovered through the Company's REPS EMF, as corrected through the Company's revised filings, represent prudently incurred costs to comply with REPS. He also stated that, if during the billing period, DEP does not recover all of its prudent costs, DEP should be allowed to recover those costs through the EMF and the customer should pay those legitimate costs.

Witness Boswell stated in her affidavit that the Public Staff's investigation included procedures intended to evaluate whether the Company properly determined its per books incremental compliance costs and revenues, as well as the annual revenue cap for REPS requirements, during the test period. She stated that these procedures included a review of the Company's filing and other Company data provided to the Public Staff, as well as a review of certain specific types of expenditures impacting the Company's costs, including labor and research and development costs. Witness Boswell stated that performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as discussions with the Company.

As a result of the Public Staff's investigation, witness Boswell recommended that DEP's proposed monthly REPS EMF riders for each customer class be approved in the amounts of $(0.05), $1.16, and $6.91, per customer account, excluding the regulatory fee, for residential, general service, and industrial customers, respectively. The REPS charges proposed by DEP are less than the annual cost caps established in G.S. 62-133.8(h)(4), which are $12.00 for residential customers, $150.00 for general service customers and $1,000.00 for industrial customers. Further, based on the evidence cited above, the Commission concludes that DEP's incremental REPS costs for the test period are reasonable and prudent and should be approved.

Therefore, the Commission approves DEP's REPS incremental costs for the test period as reasonable and prudent.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact appears in the testimony and exhibits of DEP witness Byrd.

In compliance with the Commission's November 16, 2012 Order Approving REPS and REPS EMF Riders and 2011 REPS Compliance in Docket No. E-2, Sub 1020, DEP witness Byrd supplied testimony and exhibits on the results and status of various research studies for which DEP sought cost recovery in this proceeding. Witness Byrd provided the following information:

- DEP partnered with Pacific Northwest National Laboratory and Clean Power Research to research the operational impacts of solar at various penetration levels. Specifically, studies address the ancillary services impact of solar at the system level based on granular solar photovoltaic forecasts in the Company's service territory. The final report can be found at http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

- Rocky Mountain Institute (RMI) – The Company participates in eLab, a forum sponsored by RMI, that is organized to overcome barriers to economic deployment of distributed energy resources. The Company seeks to gauge customer desires related to distributed resources and provide ideas of potential long-term solutions for distributed energy resources and microgrids. Company-specific reports and findings are not yet available; however, publicly available reports from e-Lab can be found at www.rmi.org/elab.

- The Company commissioned UNC-Chapel Hill to analyze wind resources outside the barrier islands where potential may exist for large scale offshore wind projects. There is not currently sufficient data to determine the feasibility of offshore wind projects in this area. Field data collection, modeling, and analysis work are ongoing.

- Electric Power Research Institute (EPRI) – In 2013, the Company subscribed to the following EPRI programs, the costs for which were recovered via the REPS rider: Program 84 – Renewable Energy Economics and Technology; Program 187 –

Solar; Program 188 – Biomass. EPRI designates such study results as proprietary or as trade secrets and licenses such results to EPRI members, including the Company. As such, the Company may not disclose the information publicly. Non-members may access these studies for a fee. Information regarding access to this information can be found at http://www.epri.com/Pages/Default.aspx.

- Other Resources and Subscriptions – The Company subscribes to various renewable energy news and trade publications to gain access to market analyses, including price and supply/demand trends for renewable energy. Such publications are generally proprietary and provided to the Company under confidentiality licenses and, as such, the Company may not disclose the information. Interested parties can obtain copies of such reports and analyses for a fee. The Company subscribes to or has purchased services from several publications including Bloomberg New Energy Finance, IHS Global, Megawatt Daily, and SolarBuzz.

According to Byrd Revised Exhibit No. 2, DEP spent $317,248 on REPS-related research during the test period; the Company plans to spend $350,000 during the billing period. The Commission concludes that the costs of the research activities funded by DEP during the test period and planned for the billing period are reasonable and prudent. Further, the costs are within the statutory $1-million annual limit. Therefore, the costs are recoverable pursuant to G.S. 62-133.8(h)(1)(b). In addition, the Commission finds that the research information DEP provided is helpful. Therefore, DEP shall continue to file this information with future REPS compliance reports.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact appears in the affidavit of Public Staff witness Lucas, the testimony of witness Byrd, and the Commission's Order Approving REPS and REPS EMF Riders and 2013 REPS Compliance (DEC REPS Order), issued on August 21, 2014, in Docket No. E-7, Sub 1052, the 2014 REPS rider proceeding for Duke Energy Carolinas, LLC.

Public Staff witness Lucas stated in his affidavit that many of DEP's REC purchase contracts, like those of DEC, require the REC seller to provide environmental attributes other than those included in the statutory definition of a REC in G.S. 62-133.8(a)(6). Witness Byrd agreed that the REC purchase contracts that are used by DEP are similar to those that are used by DEC, and that the language regarding environmental attributes is the same. In its DEC REPS Order, the Commission declined to require DEC to change its REC purchase contracts, but stated that:

> [i]n the future, if it is demonstrated that DEC is incurring additional incremental costs due to contract provisions that cause it to unnecessarily purchase emission reduction attributes, DEC will have the burden of showing that such costs are appropriate for recovery from its North Carolina retail ratepayers.

Witness Lucas recommended that the Commission's ruling on this matter in the DEC REPS Order also apply to DEP's REC purchase contracts. Neither of DEP's witnesses took issue with witness Lucas's recommendation. The Commission concludes that it is appropriate for DEC and DEP to be treated in the same manner with regard to these contracts.

IT IS, THEREFORE, ORDERED as follows:

1. That effective for service rendered on and after December 1, 2014, DEP shall be allowed to charge each residential customer a monthly EMF of ($0.05) and a REPS rider in the amount of $0.88, for a total of $0.83; DEP shall be allowed to charge each general service customer a monthly EMF of $1.16 and a REPS rider in the amount of $4.94, for a total of $6.10; and DEP shall be allowed to charge each industrial customer a monthly EMF of $6.91 and a REPS rider in the amount of $17.62, for a total of $24.53, excluding the regulatory fee.

2. That DEP shall file appropriate rate schedules and riders with the Commission to implement the provisions of this Order no later than 10 days from the date of this Order.

3. That DEP shall work with the Public Staff to prepare a joint proposed notice to customers of the rate changes ordered by the Commission in Docket No. E-2, Subs 1043, 1044, and 1045, and the Company shall file the proposed customer notice for Commission approval as soon as practicable.

4. That DEP's 2013 REPS compliance report is hereby approved, and the RECs in DEP's 2013 compliance sub-accounts in NC-RETS shall be retired.

5. That DEP shall file in all future REPS rider applications the results of studies the costs of which were recovered via its REPS rider, including the overall program number and specific project number for each project sponsored by EPRI; and for those studies that are subject to confidentiality agreements, information (including an internet or mailing address) regarding how parties can access the results of those studies.

ISSUED BY ORDER OF THE COMMISSION.
This the _21st_ day of November, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. EC-82, SUB 15

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition by EnergyUnited for Approval	)	ORDER APPROVING
of Energy Efficiency Programs	)	PROGRAM REVISIONS

BY THE COMMISSION:On November 12, 2013, EnergyUnited Electric Membership Cooperative (EnergyUnited) filed an application requesting approval to modify its Residential Heat Pump Energy Efficiency Rebate program (Heat Pump Program) and its Commercial and Industrial Energy Efficiency Lighting program (Lighting Program). These programs were originally approved as new energy efficiency programs pursuant to G.S. 62-133.9 and Commission Rule R8-68 on September 22, 2009, in Docket No. EC-82, Sub 10. Each program has been and will continue to be used by EnergyUnited to meet its obligations under the Renewal Energy and Energy Efficiency Portfolio Standard (REPS) pursuant to G.S. 62-133.8.

The proposed modifications to the Heat Pump Program will increase the energy efficiency qualifications (based on the Seasonal Energy Efficiency Ratio or SEER of the new heat pump equipment) as follows:

Participant Incentive	Qualifications (Min. SEER Rating)	
	Current	Proposed
$150	14	15
$300	15 or greater	16 or greater

With respect to the Lighting Program, EnergyUnited proposes to expand the availability of lighting measures to include outdoor and street lighting measures using LEDs (light emitting diodes) and to reduce the participant incentive amount from $0.30 per watt saved to $0.20 per watt saved.

In its application, EnergyUnited provided the results of its cost effectiveness calculations. Those results indicate that the Heat Pump Program is cost effective under the Participant, Total Resource Cost, and Utility Cost tests, but not the Ratepayer Impact Measure test. The Lighting program is cost effective under all four tests.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on January 6, 2014. The Public Staff indicated that it had reviewed EnergyUnited's requests, including a review of the evaluation, measurement, and verification plans submitted in the original program approval docket, and its 2012 and 2013 REPS compliance plans dockets filed in Docket Nos. E-100, Sub 137 and 139 respectively. Based on its review, the Public Staff recommended approval of the requests to modify the Heat Pump and Lighting programs.

Based on the foregoing, the Commission finds good cause to approve as filed, pursuant to Commission Rule R8-68, EnergyUnited's modifications to its Residential Heat Pump Energy Efficiency Rebate Program and Commercial and Industrial Energy Efficiency Lighting Program.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __8th__ day of January, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris. Deputy Clerk

DOCKET NO. A-75, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Island Express Ferry Services, LLC, 412 Front Street, Beaufort, North Carolina 28516 – Application to Transport Passengers in Ferry Operations	)))	ORDER GRANTING COMMON CARRIER AUTHORITY

BY THE COMMISSION: On October 22, 2013, Island Express Ferry Services, LLC (Applicant), filed with the Commission in the above-captioned docket an application seeking certain common carrier authority, which was particularly described in the Commission Order dated December 11, 2013, assigning the matter for hearing.

On December 20, 2013, the Applicant filed a Motion Requesting a Declaratory Ruling. In its motion, the Applicant requests that the Commission exercise its discretion to refrain from exercising its tariff and rate authority in this docket. In support of the motion, the Applicant shows the Commission that it has been awarded Concession Contract No. CALO001-14 by the United States Department of Interior, National Park Service (NPS), to provide ferry services from Beaufort and Harkers Island to South Core Banks and Shackleford Banks and to provide land transportation services on the South Core Banks within Cape Lookout National Seashore. On December 27, 2013, NPS Superintendent Patrick M. Kenney filed a letter in support of the Applicant's motion. On January 13, 2014, the Applicant filed copies of the following documents: Operating Plan, Ferry/Tour Price List, and Concession Contract No. CALO001-14.

No protests to the application were filed with the Commission within the time prescribed by the December 11, 2013 Order. On January 16, 2014, the Applicant requested that the Commission cancel the hearing and decide the matter on the basis of the existing record. By Order dated January 17, 2014, the hearing was canceled, with the matter to be decided upon the application and other matters of record in this docket.

Upon consideration of the application, the Applicant's motion, and the entire record in this docket, the Commission finds and concludes that:

1. the public convenience and necessity require that the proposed service be offered in addition to existing authorized transportation service;

2. the Applicant is fit, willing, and able to properly perform the proposed service on a continuing basis;

3. the Applicant is solvent and financially able to furnish adequate service on a continuing basis;

4. the Applicant has satisfied the burden of proof imposed by G.S. 62-262(e); and

5. the Applicant should be granted the authority described in Exhibit A attached to this Order.

With regard to the Applicant's Motion Requesting a Declaratory Ruling, the Commission finds that it is not appropriate to allow the motion on the facts before it. There are a handful of past instances in which the Commission has refrained from subjecting an entity to its regulatory jurisdiction because the entity's offer of service was not to sufficient of the public to clothe the entity's operation with the public interest. However, in the regulatory circumstances of this case, the Applicant's service will be offered, to the extent of the Applicant's capacity, to all of the public who wish to be transported to Cape Lookout National Seashore from Beaufort and Harkers Island. Thus, notwithstanding the concession contract with NPS, the Applicant remains a public utility clothed with a public interest because its service will be offered to sufficient of the public for compensation as contemplated by G.S. 62-3(23)(a)(4). Accordingly, the Applicant's motion should be denied, and the Applicant is subject to regulation by the Commission because it is offering a service to the public within the meaning of G.S. 62-3(23)(a)(4). See State ex rel. Utilities Comm'n v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978).

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant is hereby granted the common carrier authority set forth in Exhibit A attached to this Order and made a part hereof.

2. That the Applicant shall file with the North Carolina Utilities Commission, Operations Division, evidence of the required liability insurance and designation of process agent, and shall file with the Public Staff – North Carolina Utilities Commission, Transportation Rates Division, a tariff of rates and charges, timetable, and otherwise comply with the rules and regulations of the Commission.

3. That unless the Applicant complies with the requirements set forth in Ordering Paragraph 2 above and begins operating as herein authorized within 30 days after the date of this Order, unless such time is extended in writing by the Commission upon request for such extension, the operating authority granted herein will cease.

4. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information required in the prescribed Annual Report to the Commission are available for use by the Applicant in the preparation of such Annual Report. A copy of the Annual Report form shall be furnished to the Applicant upon request to the Transportation Rates Division.

5. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information requested in its prescribed quarterly Public Utilities Regulatory Fee Report are available for use by the Applicant in the preparation of such report and payment of quarterly regulatory fee. Any questions regarding the regulatory fee report and/or regulatory fee should be directed to the Commission's Fiscal Management and Administrative Division at 919-733-5265.

6. That this Order shall constitute a certificate until a formal certificate has been issued and transmitted to the Applicant authorizing the common carrier transportation described and set forth in Exhibit A attached hereto.

7. That the Applicant's December 20, 2013 Motion Requesting a Declaratory Ruling shall be, and is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the _31st_ day of March, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. A-75, SUB 0

ISLAND EXPRESS FERRY SERVICES, LLC
412 Front Street
Beaufort, North Carolina 28516

REGULAR ROUTE COMMON CARRIER AUTHORITY

EXHIBIT A

Transportation of passengers and their personal effects, via water in ferry operations, from Beaufort and Harkers Island to South Core Banks and Shackleford Banks, and return.

DOCKET NO. G-63, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Petroleum Fuel & Terminal Company for a Declaratory Ruling with Regard to Jurisdiction and Permission to Receive Natural Gas Through a Piedmont Natural Gas Company, Inc. Pipeline	)))))	ORDER FINDING PIPELINE SAFETY LAWS APPLICABLE AND GRANTING A SPECIAL PERMIT ON CONDITIONS

BY THE COMMISSION: On December 16, 2013, Petroleum Fuel & Terminal Company (PF&T), filed a Petition for Declaratory Ruling in the above-captioned docket. In summary, PF&T states that a wholly-owned subsidiary of PF&T, PF&T NGPipeline Company, LLC, was created for the purpose of constructing a natural gas pipeline from PF&T's facility at 3314 River Road in Wilmington, North Carolina, for a distance of 1600 feet to the existing natural gas meter station located on River Road and owned by Piedmont Natural Gas Company, Inc., (Piedmont). PF&T further states that its intent was to have Piedmont operate and maintain the pipeline for the sole purpose of delivering natural gas to PF&T, but that Piedmont will not agree to do so. PF&T submits that Piedmont's refusal to do so is based on Piedmont’s concern that the soil in which the pipeline is buried is contaminated with para-xylene. In its Petition, PF&T provides numerous design and other details regarding the construction of the pipeline, the materials used for the pipeline and the precautions taken to prevent any possible damage to the pipeline by contaminated soil. PF&T maintains that Piedmont's refusal to operate and maintain the pipeline is unreasonable.

On January 28, 2014, the Commission issued an Order Serving Petition and Requiring Responses requiring, among other things, that PF&T and Piedmont exchange information, that Piedmont file a response to PF&T's Petition, and that the Public Staff participate in this matter.

On February 21, 2014, Piedmont filed its Answer to PF&T's Petition. In summary, Piedmont states that it declined to build a fuel line to PF&T's facility because of uncertainty about the degree of soil contamination in the area. Piedmont further states that PF&T built the fuel line and is receiving natural gas service from Piedmont. Piedmont takes the position that the fuel line is a customer-owned line extending from PF&T's meter to PF&T's business premises, and, therefore, the fuel line is not subject to regulation by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) or the Commission. Piedmont discusses several PHMSA statutes and regulations. In addition, Piedmont cites PHMSA Interpretation No. PI-75-011 (March 20, 1975), the North Carolina Fuel Gas Code, Piedmont's Service Regulations and Piedmont's tariffs in support of its conclusion. Further, Piedmont states that it has discussed the operation and jurisdictional aspects of the fuel line with PF&T, and that the two parties have reached the mutual conclusion that the fuel line is not subject to PHMSA or Commission regulation. Finally, Piedmont states that Piedmont and PF&T request that this docket be closed without further action by the Commission because there is no justiciable controversy.

On March 6, 2014, the Public Staff filed comments stating that it agrees with Piedmont's and PF&T's position that the fuel line is properly owned and operated by PF&T and is not subject to regulation by the Commission. With respect to PHMSA regulation, the Public Staff defers to the Commission for an interpretation of PHMSA's statutes and regulations.

On April 16, 2014, the Commission issued an Order Requiring Further Response in which the Commission stated its understanding that the path of PF&T's fuel line is not confined solely to PF&T's property. In particular, the Commission noted that PF&T states that in April 2013 it entered into an easement agreement with NuStar Logistics, LP (NuStar), and that this statement implies that the fuel line, or some portion of the fuel line, traverses property owned by NuStar. In addition, the map attached to PF&T's Petition as Attachment A shows that the fuel line crosses River Road. The Commission stated that the authorities relied upon by Piedmont in its Answer do not address the situation in which a fuel line traverses property owned by another person or a public right-of-way. However, both of those points are addressed in PHMSA Interpretation No. PI-09-0020 (August 11, 2010). Therefore, the Commission's April 16, 2014 Order required PF&T, Piedmont and the Public Staff to consider the fact that PF&T's fuel line traverses property owned by another person and a public right-of-way, and to advise the Commission whether this fact changes their view about the fuel line being subject to PHMSA regulations.

On April 30, 2014, the Public Staff filed comments quoting, in pertinent part, the provisions of G.S. 62-15(d)(8), that “the public staff shall have no duty, responsibility, or authority with respect to the enforcement of natural gas pipeline safety laws, rules or regulations.” Thus, the Public Staff states that it continues to defer to the Commission for an interpretation of PHMSA's statutes and regulations.

On May 1, 2014, the Commission issued an Order Granting Extension of Time approving PF&T's motion to allow all parties additional time to file their comments. The Order extended the due date from May 5, 2014, to June 2, 2014.

On June 2, 2014, Piedmont and PF&T filed joint comments in response to the Commission's April 16, 2014 Order. In summary, Piedmont and PF&T opine that the PF&T fuel line is different from the situation addressed in PHMSA Interpretation No. PI-09-0020 because it is more analogous to “in plant piping,” which is exempt from PHMSA regulation, in that it is operated by PF&T personnel, runs from Piedmont's meter to PF&T's facility, and is less than one mile in length. Further, they note that PF&T has an easement with NuStar, an Encroachment Agreement with the City of Wilmington that allows PF&T to use the City's right-of-way along River Road, and a license with the North Carolina State Ports Authority that allows PF&T to traverse a railroad crossing owned by the Ports Authority. Finally, Piedmont and PF&T submit that there is no public interest concern that compels the Commission to assert jurisdiction over the PF&T fuel line.

Discussion

Pursuant to G.S. 62-50(b), Commission Rule R6-39, and 49 U.S.C. § 60106, the Commission has entered into an agreement with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration that grants the Commission the authority to enforce federal pipeline safety standards with regard to all PHMSA jurisdictional natural gas pipelines located within the State of North Carolina. The pertinent PHMSA pipeline safety regulations are found at 49 C.F.R. Parts 191, 192, 193 and 199.

Pursuant to 49 C.F.R. § 192.3, PHMSA safety standards apply to natural gas and other gas gathering, transmission and distribution pipelines. Generally, these are gas pipelines that transport gas along private property by easement and along public road right-of-ways, such as streets and highways. With regard to gas lines along public road right-of-ways, the structural integrity and safe operation of these lines is a matter of public interest. On the other hand, once the gas moves from a transmission or distribution line to a fuel line serving an end-use customer that is located solely on the customer's property, it is the customer's responsibility to monitor the structural integrity and safe operation of the fuel line. Thus, PHMSA regulation typically ends at the point where pressure control changes from the transmission or distribution pipeline operator to the customer.

However, PHMSA has noted an exception to this general rule in situations where the fuel line is not located entirely on the customer's property. In PHMSA Interpretation No. PI-09-0020, United States Steel Corporation (USS) requested an interpretation regarding the applicability of PHMSA pipeline safety regulations to several pipelines operated by it at its Granite City Works (GCW) steelmaking complex in southern Illinois. The pipelines included natural gas pipelines connected from a transmission line of the Mississippi River Transmission (MRT) pipeline to several GCW facilities, and a pipeline transporting coke oven gas produced in one GCW facility and transported to another GCW facility for processing and burning. One of the systems of piping having three different connections to MRT went outside the GCW property boundaries six times.

In Interpretation No. PI-09-0020, PHMSA stated:

> [T]ypically, a transmission pipeline transporting gas to a destination facility such as a large volume customer is subject to the pipeline safety laws and regulations up to the point where pressure control changes from the pipeline operator to the destination facility operator (which can be on the grounds of the facility). Beyond that point, piping operated by the facility operator entirely on the grounds of the facility is considered "in-plant piping" and would not be subject to the pipeline safety regulations although it may be subject to State building codes or other regulations. In this case, however, the natural gas pipelines operated by GCW are not located entirely on the geographically contiguous grounds of a facility. <u>Rather, these lines depart GCW facilities and cross roads and highways accessed by the public, albeit for relatively short distances. To the extent such lines are not on plant property they are subject to the pipeline safety laws.</u> Historically, PHMSA has elected not to apply the Federal gas pipeline safety regulations to such lines if they are associated with the plant, meaning they are operated by plant personnel, run between plant buildings, and are less than one mile in length. PHMSA, however, would not object to a State regulating the portions of such lines that are not on plant property if the State determined there was a need. Note that a State that regulates its intrastate gas pipelines under a Public

> Utility Commission (PUC) may need to determine whether the PUC is restricted to only regulating "public utilities" which GCW presumably is not.
>
> …
>
> With respect to the coke oven gas pipeline, you stated that a mixture of gaseous hydrocarbons produced by the facility is transported several thousand linear feet before it is burned. You further stated that most of this distance is located under the public right of way, some of which runs beneath a public sidewalk outside the fence from the facility in which the gas is burned. Because the coke oven gas is produced in one GCW facility and is transported to another GCW facility under public right-of-way and public sidewalk, this pipeline is subject to the pipeline safety regulations.

PHMSA Interpretation No. PI-09-0020, at p. 2 (emphasis added).

The Commission concludes that the underlined portion of the above interpretation is the operative language for purposes of the present docket. The fact that PF&T's fuel line traverses the public right-of-way on River Road has the potential to impact the safety of the public. Thus, the fuel line is no longer totally the private concern of PF&T. Rather, the structural integrity and safe operation of the line is a matter of public interest. Further, the Commission is not persuaded by the argument that PF&T's Encroachment Agreement with the City of Wilmington that allows PF&T to use the City's right-of-way along River Road obviates the need for public safety. The fact that PF&T has the legal right to use the City's public right-of-way does not diminish the risk of a release of gas or an explosion that could injure a member of the public who is traveling River Road without any knowledge that the road has a natural gas pipeline underneath it. Persons traveling on a public road should not be required to assume that risk. As a result, the Commission concludes that the line is subject to the PHMSA safety standards.

However, in appropriate situations the Commission may grant a special permit that varies the PHMSA compliance requirements for a pipeline operator if the special permit is not inconsistent with pipeline safety. In addition, a special permit granted by the Commission is subject to final approval by PHMSA. The special permit must be submitted to PHMSA at least 60 days prior to its effective date. See 49 U.S.C. § 60118, and 49 C.F.R. § 190.341.

Based on the specific circumstances in this docket, there are several facts that support the granting of a special permit to PF&T for the operation of this fuel line. First, it is a relatively short fuel line of only 1600 feet. Second, the maximum delivery pressure from Piedmont is a relatively low pressure of 20 psig. This is less than 2% of the Specified Minimum Yield Strength (SMYS) of the steel pipe used to construct the fuel line. Third, the pipe, valves, and fittings have been strength tested to a minimum of 90 psig. Fourth, the fuel line was constructed using seamless steel pipe and coated with a protective coating to make the pipe highly chemically resistant to gasoline and naphtha, both of which contain xylene. Finally, the portion of the fuel pipeline that traverses the River Road right-of-way is very short, only about 63 feet.

However, the Commission will require PF&T to comply with certain conditions in order to receive this waiver of PHMSA compliance requirements. Those conditions are:

1. That on or before September 1, 2014, and at least once each calendar year thereafter, in accordance with the requirements of 49 C.F.R § 192.465(a), PF&T shall have a qualified person test the fuel line to determine whether the cathodic protection meets the requirements of 49 C.F.R § 192.463. Within seven (7) days of these inspections, PF&T shall file a report with the Commission's Pipeline Safety Section detailing the actions taken during these inspections and the findings.

2. That on or before September 1, 2014, and at least six times each calendar year, in accordance with the requirements of 49 C.F.R § 192.465(b), PF&T shall have a qualified person inspect the cathodic protection rectifier to ensure that it is operating properly. Within seven (7) days of any such inspection in which it is determined that the cathodic protection rectifier was not operating properly, PF&T shall file a report with the Commission's Pipeline Safety Section detailing the problem with the cathodic protection rectifier, the actions taken by PF&T to correct the problem, and the date on which the cathodic protection rectifier was restored to its proper operation.

3. That on or before September 1, 2014, and at least once every twenty-four (24) months thereafter, PF&T shall have a qualified person perform a leak survey of the entire fuel line. If PF&T detects a leak on the fuel line, PF&T shall immediately close the fuel line and shall notify the Commission's Pipeline Safety Section within two (2) hours.

4. That on or before September 1, 2014, PF&T shall register as an operator, pursuant to G.S. 87-115, et seq., with the NC811 Notification Center.

5. That on or before September 1, 2014, PF&T shall post "Call NC811 Before You Dig" information notices on each side of River Road at the point that PF&T's fuel line enters the public right-of-way.

6. That PF&T shall notify the Commission in writing at least ninety (90) days before PF&T makes any structural or location change, any capacity addition, or any pressure increase to the fuel line.

7. That additional safety measures may be required by the Commission if the Commission determines that such measures are necessary to maintain the safe operation of the fuel line.

8. That irrespective of any changes in PHMSA requirements or regulations, PF&T must petition the Commission for any changes in this special permit and these conditions.

Conclusion

Based on the foregoing and the record in this docket, the Commission finds good cause to grant PF&T this special permit to operate its fuel line.

IT IS, THEREFORE, ORDERED as follows:

1. That Petroleum Fuel & Terminal Company is hereby granted a special permit, with conditions, for the operation of the fuel line serving its facility at 3314 River Road in Wilmington, North Carolina.

2. That the Chief Clerk of the Commission shall send a copy of this Order to the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration by certified mail.

3. That this special permit shall not be effective until one of the two following events occurs: (1) the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration takes no action on the special permit within sixty (60) days after receiving the Commission's Order, or (2) the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration issues an Order approving the special permit.

ISSUED BY ORDER OF THE COMMISSION.
This the __1st__ day of July, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. G-9, SUB 649

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Piedmont Natural Gas Company, Inc., for a Limited Waiver of Rate Schedule 106 Billing Procedures	)))	ORDER ON PETITION FOR LIMITED WAIVER OF RATE SCHDULE 106 BILLING PROCEDURES

HEARD: Tuesday, June 17, 2014 at 9:30 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

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

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, Bank of America Corporate Center, 100 North Tryon Street, Suite 4700, Charlotte, North Carolina 28202

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

For the North Carolina Utilities Commission:

Len Green, Senior Staff Attorney, - North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On April 11, 2014, Piedmont Natural Gas Company, Inc. (Piedmont or Company) filed a Petition for Limited Waiver pursuant to G.S. 62-32 and Commission Rules R1-4 and R1-5 requesting a limited waiver of its Rate Schedule 106 billing procedures. The requested waiver was applicable to Emergency Services and Unauthorized Gas provided to Piedmont's interruptible customers during January 2014, on days that Piedmont’s interruptible customers were notified to curtail their gas usage. In summary, Piedmont requested that the Commission enter an Order authorizing Piedmont to waive the portion of Rate Schedule 106 that required that interruptible customers that received Emergency Service and Unauthorized Gas pay the higher of two commodity index charges.

On April 17, 2014, the Commission issued its Order to Show Cause, Scheduling Hearing and Requiring Customer Notice. Pursuant to the Order, a schedule for the filing of testimony by Piedmont, the Public Staff and other interested parties was established and an evidentiary hearing was scheduled for June 17, 2014.

On May 19, 2014, Piedmont filed the direct testimony and exhibits, some of which contained confidential information, of Pia K. Powers, Director of Regulatory Affairs of the Company, and the direct testimony of Frank Yoho, Senior Vice President and Chief Commercial Officer of the Company.

On May 22, 2014, the Commission issued an Order Requiring Supplemental Exhibit and Additional Information.

On May 30, 2014, the Public Staff filed a motion for extension of time until June 5, 2014, to file its testimony. The Commission entered an Order granting the motion on June 2, 2014.

On June 4, 2014, pursuant to the Commission's Order on May 22, 2014, Piedmont filed its supplemental exhibit and additional information as requested by the Commission.

On June 5, 2014, the Public Staff filed a second motion for extension of time until June 9, 2014, to file testimony. The Commission entered an Order granting the motion on June 6, 2014.

On June 6, 2014, Piedmont filed a revised copy of Attachment A Item 6 originally filed on June 4, 2014.

On June 9, 2014, the Public Staff filed the joint testimony of Jeffrey L. Davis, Director of the Public Staff Natural Gas Division, and Julie G. Perry, Supervisor of the Natural Gas Section in the Public Staff Accounting Division.

On June 13, 2014, Piedmont filed the rebuttal testimony of Frank Yoho and the rebuttal testimony and exhibits, which also contained confidential information, of Pia K. Powers. In addition, Piedmont filed a Motion for Leave to Testify as a Panel.

On June 17, 2014, the case was heard as scheduled in Raleigh. At the hearing the prefiled direct and rebuttal testimony and exhibits of the Piedmont witnesses, Frank H. Yoho and Pia K. Powers, were accepted into evidence. Further, the Commission granted Piedmont's previously filed motion to allow witness Yoho and witness Powers to testify at the hearing as a panel. In addition, the prefiled direct testimony of Public Staff witnesses Jeffrey L. Davis and Julie G. Perry were accepted into evidence. Witness Davis and witness Perry also testified at the hearing as a panel. No public witnesses appeared at the hearing.

On June 26, 2014, Piedmont filed its Confidential Late-Filed Exhibits as directed by the Commission on June 17, 2014.

On June 30, 2014, the Public Staff filed its Late Filed Exhibits as directed by the Commission on June 17, 2014.

On July 9, 2014, the Commission ordered the Public Staff to provide as a late-filed exhibit the numbers, calculations, averages and assumptions used by the Public Staff to determine Piedmont's highest cost flowing gas during January 2014.

On July 15, 2014, the Public Staff filed public and confidential versions of its late-filed exhibit in response to the Commission's Order of July 9, 2014.

On August 1, 2014, Piedmont filed a Notice of Settlement and Request for Procedural Relief. In addition to notifying the Commission of a settlement with the Public Staff, Piedmont requested a suspension of the procedural schedule established in the Notice of Due Date for Post-Hearing Filings and for additional time to file a formal Stipulation of Settlement and supporting testimony.

On August 5, 2014, the Commission granted Piedmont's request to suspend the procedural schedule. Further, the Commission granted the parties' request for an extension of time for filing the settlement documents and supporting testimony, requiring the filing of settlement documents on or before August 11, 2014.

On August 11, 2014, the parties filed their Joint Stipulation of Settlement and Piedmont filed the supporting testimony of Frank Yoho.

On September 4, 2014, the Commission accepted into evidence the Joint Stipulation of Settlement between Piedmont and the Public Staff and required Piedmont or the Public Staff to file a proposed order by September 15, 2014.

On September 10, 2014, Piedmont filed Exhibit A to the Joint Stipulation of Settlement.

On September 11, 2014, Piedmont filed a Motion for Extension of Time requesting that the time for filing a proposed order be extended to September 19, 2014.

On September 12, 2014, the Commission issued an Order granting Piedmont's Motion for Extension of Time and requiring that Piedmont and the Public Staff file a proposed order on September 19, 2014.

On September 19, 2014, the Joint Proposed Order of Piedmont and the Public Staff was filed.

Based upon the Petition, the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a corporation organized and existing under the laws of the State of North Carolina, duly authorized to do business in North Carolina, and engaged in the business of transporting, distributing, and selling natural gas within the states of North Carolina, South Carolina, and Tennessee.

2. Piedmont is a public utility within the meaning of G.S. 62-3(23).

3. The Commission has jurisdiction over, among other things, the rates and charges, rate schedules, classifications, and practices of Piedmont in its capacity as a public utility.

4. In the Petition in this docket, Piedmont requested a limited waiver of its Rate Schedule 106 billing procedures for Emergency Service and Unauthorized Gas received by certain Piedmont interruptible customers during the cold weather in the month of January 2014.

5. Piedmont plans and operates its system to serve firm customers on a design day. Piedmont's ability to curtail interruptible customers on the day of very high demand allows it to avoid the costs of building the capacity that would be needed to serve those customers on such a day. Interruptible transportation customers pay substantially lower rates than firm transportation customers in exchange for agreeing to curtail their service.

6. During January 2014, prolonged periods of cold weather were experienced in Piedmont's service territory.

7. In response to the forecasts predicting cold weather, Piedmont issued several Operational Orders which directed interruptible customers to take certain actions to restrict or modify their utilization of natural gas during anticipated periods of very high demand.

8. Piedmont's right and ability to restrict customer usage through Operational Orders is established by Sections 2, 21, and 22 of its North Carolina Service Regulations, as well as provisions of its applicable Rate Schedules.

9. The January 2014 Operational Orders were issued by Piedmont to ensure the stability of its system and to preserve its ability to make delivery of natural gas to its firm, high priority, heat sensitive customers during the high demand days in January 2014.

10. Piedmont also directly contacted certain interruptible sales and transportation customers at various times during the month of January 2014 and directed them to cease using gas.

11. The Operational Orders were specifically targeted to portions of Piedmont's system that were facing pressure issues.

12. No curtailment of service to firm customers occurred on Piedmont's system during this period.

13. Under Piedmont's tariffs, customers subject to interruption have the right to request Emergency Service in order to avoid interruption.

14. In the face of an Operational Order, and absent authorization from Piedmont for Emergency Service, continued utilization of gas by an interruptible customer in violation of such Order is prohibited and constitutes the receipt of Unauthorized Gas by that customer.

15. The interruptions of service occurred on 11 days during the month of January 2014 (Curtailment Days) and involved a total of 35 Piedmont customers. These 35 customers were receiving interruptible sales service under Rate Schedule 104 or interruptible transportation only service under Rate Schedule 114.

16. During the Curtailment Days, 26 customers receiving service under Rate Schedules 104 and 114 either requested and received Emergency Service or took Unauthorized Gas, or both. Specifically, sixteen customers requested and received Emergency Service, six of which also took quantities of Unauthorized Gas above their approved Emergency Service gas. Ten additional customers took Unauthorized Gas.

17. The total quantity of Emergency Service gas provided by Piedmont during the Curtailment Days was 187,797 therms. The total quantity of Unauthorized Gas taken by Rate Schedule 104 and 114 customers during the Curtailment Days was 19,255 therms.

18. Piedmont determined that all of its interruptible transportation customers who received Emergency Service gas had brought equivalent quantities of gas to Piedmont at its Transco city gate delivery points for their respective accounts, whereas Rate Schedule 114 customers who were considered as taking Unauthorized Gas had not brought sufficient gas to Piedmont's city gate.

19. At no time during the cold weather events was Piedmont's ability to maintain service to its firm customers in jeopardy as a result of interruptible customers taking Emergency Service gas or taking Unauthorized Gas.

20. Pursuant to Piedmont's Rate Schedule 106, Emergency Service is subject to a rate which consists of three components: (1) a transportation or sales rate depending on whether the underlying service is provided under Rate Schedule 104 or Rate Schedule 114; (2) a premium charge of $1.00 per therm reflecting the extraordinary nature of the service; and (3) a commodity rate calculated as the higher of two commodity indices applicable to the period of service.

21. Under Rate Schedule 106, Unauthorized Gas is subject to a three-part rate: (1) a transportation or sales rate depending on whether the underlying service is provided under Rate Schedule 104 or Rate Schedule 114; (2) a penalty charge of $2.50 per therm reflecting the unauthorized nature of the service; and (3) a commodity rate calculated as the higher of two commodity indices applicable to the period of service.

22. Due to the extreme spikes in the daily price of delivered gas during January 2014, the higher of the two commodity price indices identified in Piedmont's Rate Schedule 106 and applicable to Emergency Service and Unauthorized Gas usage ranged from a low of approximately $11 per dekatherm (dt) to a high of more than $123 per dt.

23. Piedmont's Benchmark Cost of Gas was $4.25 per dt during this period.

24. Piedmont did not purchase any of the high priced delivered gas for system supply during the month of January 2014. Based upon several factors, Piedmont came to the conclusion that the index price component mechanism in its tariff, which applied the commodity rate calculated as the higher of two commodity indices, was disproportionately punitive to interruptible customers.

25. Piedmont varied from its tariff and billed only the underlying volumetric tariff rates for the interruptible sales and transportation service the customers received and the premium portion of Rate Schedule 106 rates, which is $10.00 per dt for Emergency Service and $25.00 per dt for Unauthorized Gas.

26. When billing the volumetric tariff rate for the underlying interruptible sales and transportation service under Rate Schedules 104 and 114, Piedmont billed at the first step usage rate instead of all applicable step rates.

27. On February 5, 2014, Piedmont billed all of its curtailed Rate Schedule 114 - Interruptible Transportation customers that utilized Unauthorized Gas under Rate Schedule 104 - Interruptible Sales.

28. On February 5, 2014, Piedmont billed all of its curtailed Rate Schedule 104 - Interruptible Sales customers that utilized Emergency Service or Unauthorized Gas under its existing Rate Schedule 104 Interruptible Sales tariff rate.

29. Piedmont did not bill any commodity costs associated with the Emergency Service gas delivered to the interrupted transportation customers.

30. On April 11, 2014, Piedmont petitioned the Commission requesting a limited waiver of Rate Schedule 106 billing procedure to modify its billing practices for January 2014.

31. After the hearing on June 17, 2014, and as a result of a Stipulation of Settlement, Piedmont and the Public Staff agreed that the commodity index pricing mechanism should be waived and the cost of gas component of Piedmont's Rate Schedule 106 should be modified by billing customers that received Emergency Service and Unauthorized Gas at Piedmont's highest cost of flowing gas in January 2014.

32. It is not appropriate to grant a waiver of the commodity index pricing mechanism under Piedmont's Rate Schedule 106 with respect to Piedmont's curtailed interruptible sales and transportation customers for purposes of billing Emergency Service and Unauthorized Gas during the month of January 2014.

33. Piedmont's curtailed interruptible sales and transportation customers who received Emergency Service or who took Unauthorized Gas during January 2014 should be charged consistent with the commodity index pricing mechanism under Piedmont's Rate Schedule 106.

34. Piedmont asked that customers requesting Emergency Service gas bring or cause their associated marketers to bring the customers' gas to Piedmont's system. Customers who complied with that request should be given credit for the cost of volumes delivered. Such credits should be given to those marketers or the affected customers (if that customer did not use a marketer), as applicable, in accordance with Piedmont's approved cash-out procedures prescribed in Rate Schedule 107.

35. It is appropriate for Piedmont to debit or credit the Sales Customers Only and the All Customers deferred accounts, as appropriate, for the total cost of gas component associated with Emergency Service and Unauthorized Gas as authorized by the Commission, including interest.

36. Piedmont should have sought Commission guidance on this matter prior to varying from its tariff billing provisions.

37. It is appropriate to decline Piedmont's request for changes to its Rate Schedule 106 billing procedures.

38. Commission Rule R6-12(2) requires Piedmont to "Assist the customer or prospective customer in selecting the most economical rate schedule."

39. Piedmont's customers must qualify for the rate schedule that they select.

40. In February 2014, Piedmont made a decision to charge a lesser rate than the rate approved by the Commission for Emergency Service and Unauthorized Gas provided to customers during January 2014 under Rate Schedule 106.

41. Piedmont made the decision to charge a lesser rate than that approved by the Commission for Emergency Service and Unauthorized Gas before requesting Commission approval to charge such lesser rate, and without consulting with the Public Staff.

42. There is no ambiguity in Rate Schedule 106 or other justification for Piedmont's decision to charge a lesser rate for Emergency Service and Unauthorized Gas provided to customers during January 2014 under Rate Schedule 106.

43. Prior to Piedmont making its decision to charge a lesser rate under Rate Schedule 106, Piedmont was aware that it could petition the Commission for a modification of Rate Schedule 106.

44. Piedmont received payments from its interruptible customers based on the lesser rate that Piedmont billed for interruptible service provided to customers during January 2014 under Rate Schedule 106.

45. Piedmont knowingly and intentionally charged and received a lesser rate than the rate approved by the Commission for Emergency Service and Unauthorized Gas provided to customers during January 2014 under Rate Schedule 106.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

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, the testimony of Piedmont witness Yoho, and the testimony of the Public Staff witnesses.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence for these findings of fact is contained in the Petition and the testimony of Piedmont witnesses Yoho and Powers

Piedmont witness Yoho testified that Piedmont plans the capacity of its system based on the projected design day demand of the firm customers. He agreed that if Piedmont has the ability to cease serving a customer on the day of very high demand, then it can avoid building the capacity needed to serve that particular customer. Witness Yoho also testified that building additional capacity would increase Piedmont's costs and result in higher rates to Piedmont's customers.

Witness Powers testified that during Piedmont's last fiscal year approximately 27% of Piedmont's throughput went to serve its interruptible customers. Witnesses Yoho and Powers agreed that in planning its system Piedmont relies heavily on its ability to curtail its interruptible customers. Witness Yoho testified that interruptible rate schedules have been available to Piedmont's customers since the 1990s. Further, he testified that one reason large customers subscribe to interruptible service is because they receive lower rates in exchange for taking the risk of being interrupted.

The Piedmont witnesses were shown Commission Piedmont Cross-Exam Exhibit No. 1 that included calculations demonstrating that under Piedmont Rate Schedule 114 – Interruptible Transportation Service, Piedmont's interruptible transportation customers pay 36.3% less for the first 15,000 therms than firm customers pay for the first 15,000 therms under Piedmont Rate Schedule 113 – Firm Transportation Service. The witnesses agreed that this is an accurate calculation of the difference in Piedmont's interruptible and firm transportation rates at that level of usage. They also agreed that a second calculation shown on Commission Piedmont Cross-Exam Exhibit No. 1 for service at 45,000 therms accurately shows that Piedmont's interruptible transportation customers pay 28.6% less for the first 45,000 therms under Piedmont Rate Schedule 114 – Interruptible Transportation Service than firm customers pay for the first 45,000 therms under Piedmont Rate Schedule 113 – Firm Transportation Service.

Based on Piedmont's Rate Schedules 103 – Large General Sales Service, and Rate Schedules 104 – Interruptible Sales Service, the Commission notes that Piedmont's rates for interruptible sales customers are lower than the rates for Piedmont's firm sales customers, although not with the degree of difference discussed above for interruptible transportation customers. However, Piedmont had only 21 interruptible sales customer accounts in January 2014, as compared to 286 interruptible transportation customer accounts. See Piedmont's Supplemental Exhibit and Additional Information, Responses 1, 2 and 3 (June 4, 2014).

Based on the evidence, the Commission concludes that Piedmont's ability to rely on its interruptible customers, particularly its interruptible transportation customers, is an important part of Piedmont's planning and operation of its system. Further, in exchange for agreeing to curtail their service Piedmont's interruptible transportation customers pay substantially lower rates than Piedmont's firm transportation customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-21

The evidence for these findings of fact is contained in the Petition, the testimony of Piedmont witnesses Yoho and Powers, and the joint testimony of Public Staff witnesses Davis and Perry.

Piedmont witness Powers testified that during January 2014, North Carolina "experienced severe cold weather conditions for a significant number of days during that month." These conditions caused Piedmont to experience the highest throughput on its system it has ever experienced and, in several instances, caused Piedmont to issue Operational Orders under its tariff to maintain close compliance with monthly and daily balancing restrictions. Piedmont's authority to issue Operational Orders is established by Sections 2, 21, and 22 of Piedmont's North Carolina Service Regulations, as well as provisions of the applicable Piedmont rate schedules. These interruptions were limited to a small number of customers (35) and were required because of pressure issues that arose on the geographic portion of Piedmont's system where those specific customers were located. Witness Powers testified that in January 2014 Piedmont had 21 interruptible sales customers and 286 interruptible transportation customers. The specific days upon which Piedmont directed specified interruptible customers to cease using gas were January 6-8, 21-24, and 27-30 (Curtailment Days).

Piedmont witness Yoho testified that Piedmont retained its ability to maintain service to its firm customers at all times during the severe cold weather events in part because the Unauthorized Gas taken by the interruptible customers was negligible and was calculated at less than 0.02% of the total gas flowing through Piedmont's North Carolina system during the time period. Accordingly, the Unauthorized Gas had no impact on system operations and posed no risk to either the stability of the system or Piedmont's ability to provide service to firm customers. Piedmont witness Yoho also testified that imbalance tolerances throughout the industry typically are set at 5%, which puts into context the minor nature of Unauthorized Gas taken in January.

Witness Yoho also testified that with respect to the 35 interruptible customers that took Emergency Service and/or Unauthorized Gas, the total throughput during the relevant time period was 20,604 dekatherms (later corrected by witness Yoho to be 207,052 dekatherms) as compared to total system throughput of 17,900,000 dekatherms.

Piedmont witnesses Yoho and Powers testified that the January 2014 curtailment directives to 35 interruptible customers were, in all cases, the result of prevailing pressure conditions on Piedmont's system in the vicinity of the impacted customers and were undertaken to preserve Piedmont's ability to maintain firm service on the affected part of Piedmont's system. They further testified that the provision of Emergency Service is within Piedmont's discretion and is only made available if it will not threaten the continued provision of service to Piedmont's firm customers.

Piedmont witnesses Yoho and Powers testified that because Piedmont does not have electronically controlled valves in place at every Rate Schedule 104 and 114 customer location, the Company relies on the customers' compliance with its Operational Orders. In the face of such an order, any continued utilization of gas by an interruptible customer is prohibited and constitutes the receipt of Unauthorized Gas by that customer.

Piedmont witness Powers testified that Rate Schedule 106 is a stand-alone rate schedule addressing the limitation and curtailment of service. Rate Schedule 106 explains the circumstances under which Piedmont can interrupt or curtail services to its customers and the processes and procedures applicable to such interruption or curtailment. Rate Schedule 106 provides that customers receiving interruptible service can be interrupted or curtailed by Piedmont "at any time and for any reason deemed necessary or appropriate by the Company." In the event of such an interruption or curtailment of service, the customer has the obligation to "take all reasonably available measures to adjust their deliveries to the Company in order to minimize any imbalances on upstream pipelines" and also has the responsibility for resolving all such imbalances on upstream pipelines. At the discretion of Piedmont, a customer may receive "Emergency Service" under Rate Schedule 106 if requested by the customers and approved by Piedmont.

Public Staff witnesses Davis and Perry testified that they viewed billing under Rate Schedule 106 after a curtailment event as a three-part process. The first part is a tariff rate component, which is based on the total volumes burned for the month for each customer using the volumetric rates set forth on the Company's tariff sheet for the underlying rate schedule applicable to the customer. The second part is a penalty component, and the third part is a cost of gas component. The penalty component is a fixed amount charged for the specific type of gas service taken by a customer after being given a curtailment notice. Once a curtailment notice is given to a customer, Rate Schedule 106 states Piedmont may provide Emergency Service to that customer if the customer requests it. Curtailed customers who otherwise use gas without permission are deemed to have burned Unauthorized Gas. The cost of gas component for both Emergency Service and Unauthorized Gas is calculated by using the higher of two commodity indices, which is defined in the tariff.

Based on the testimony and exhibits, the Commission concludes that Piedmont appropriately issued curtailment notices to its interruptible customers in accordance with its tariffs, as warranted by the January 2014 weather conditions, to preserve its system integrity. The Commission further concludes that Piedmont provided Emergency Gas to several interruptible customers and that several interruptible customers used Unauthorized Gas pursuant to the terms of Piedmont's Rate Schedule 106.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22 – 37

The evidence for these findings of fact is contained in the testimony of Piedmont witnesses Yoho and Powers, the joint testimony of Public Staff witnesses Davis and Perry, and in the late filed exhibits.

Piedmont witness Powers testified that for interrupted transportation customers receiving Emergency Service, the Company charged (1) the underlying Rate Schedule 114 first step usage rate, and (2) the premium/penalty rate of $10 per dt, but did not charge the index price component specified under Rate Schedule 106.

Piedmont and Public Staff witnesses testified that the total billed under Piedmont's modifications to Schedule 106 was $280,986.83; the total amount that would have been billed without any modification to Schedule 106 would have been $1,481,197 for a difference of $1,200,210. The penalty charges ($10.00 per dt and $25.00 per dt) are credited to the all-customers deferred account. The commodity index price mechanism charges are credited to the sales customers deferred account.

Piedmont witnesses Powers and Yoho testified that 80% of the Emergency Service or Unauthorized Gas was for interruptible transportation customers that brought their own gas onto the system and approximately 10% each for Unauthorized Gas and Emergency Service sales customers. Therefore, approximately 90% of the gas was for Emergency Service that was specifically requested. Piedmont authorized those quantities after checking with their system engineers.

Piedmont witnesses Powers and Yoho testified that Piedmont did not source any of the Emergency Service gas actually delivered to the interrupted transportation customers. In the case of transportation customers receiving service under Rate Schedule 114, Piedmont conditioned the approval of Emergency Service on the delivery by those customers of the underlying quantities of gas to Piedmont at its city gate delivery points. Piedmont's customers complied with this request and all Emergency Service provided to Piedmont's transportation customers was provided using gas supplied by those customers. In her rebuttal testimony, Piedmont witness Powers reiterated that Piedmont's primary logic for its decision was due to the fact that interrupted transportation customers who received Emergency Service in January 2014 provided their own gas to Piedmont's system at the request of the Company. This gas helped to support the operation of Piedmont's system during this period of high demand and did not require Piedmont to purchase any gas or utilize any system supply to support Emergency Service to these customers. This circumstance had not occurred in prior curtailment events where Piedmont provided Emergency Service. Piedmont witness Yoho testified in his rebuttal testimony that the Emergency Service provided in January 2014 was fundamentally a transportation service whereas the underlying presumption of Rate Schedule 106 is that it is a sales service. The increased gas brought on to the Piedmont system during the severe weather events was beneficial to the high demand requirements of the system and to all customers. The specific customers had their own supply delivered into Piedmont's system and paid their suppliers for their volumes.

Piedmont witnesses Yoho and Powers testified that Piedmont was not required to purchase any additional daily market-priced gas at extreme market prices to provide Emergency Service gas. The total amount of Emergency Service and Unauthorized Gas consumed was 207,052 therms. Piedmont's firm and interruptible sales customers paid for that gas. Further, Piedmont's interruption of service was caused by localized pressure issues, not supply shortages. Finally, Piedmont felt it unjustified to charge customers up to $123 per dt, on top of a $25 per dt penalty charge, for gas that Piedmont did not buy, which Piedmont felt would cause an economic hardship on its customers in this specific instance.

Public Staff witnesses Davis and Perry testified that Piedmont only billed the first step usage rate for the underlying interruptible sales and transportation rate schedules and did not bill all of the step usage rates applicable to the volumes that were burned. The Company charged the curtailed interruptible sales and transportation customers the applicable penalty amount for the specific type of gas service taken. However, Piedmont did not bill the commodity index price component for its curtailed Schedule 114 - Interruptible Transportation customers that took Emergency Service if their marketer brought gas to Piedmont's city gate. Piedmont billed all of its curtailed Rate Schedule 114 - Interruptible Transportation customers that utilized Unauthorized Gas under Rate Schedule 104 - Interruptible Sales. Piedmont billed all of its curtailed Rate Schedule 104 - Interruptible Sales customers that utilized Emergency Service or Unauthorized Gas under its existing Rate Schedule 104 Interruptible Sales tariff rate.

The Public Staff testified that, with respect to interruptible sales customers, Piedmont charged the Rate Schedule 104 usage rate and the premium/penalty rate of $10 per dt. Piedmont also charged the benchmark cost of gas included in Rate Schedule 104; however, the Public Staff believed this rate was not sufficient to cover the cost of gas supply actually incurred by Piedmont to serve these customers.

Public Staff witnesses Davis and Perry testified that Piedmont historically has consistently billed Emergency Service and Unauthorized Gas in compliance with the terms of its tariff. At the time the gas cost component of Rate Schedule 106 was approved, however, there was no reason to anticipate such large price differentials as occurred in January 2014. The Public Staff witnesses agreed that applying the Rate Schedule 106 cost of gas tariff calculation to gas received during the curtailment events in the month of January 2014 would be financially burdensome to the affected interruptible customers. However, the Public Staff believed that those customers should pay a cost of gas component, which would be more consistent with the structure of Rate Schedule 106. Strict adherence to Rate Schedule 106 would have produced bills at unprecedented high levels and the Pubic Staff reiterated that Piedmont did not have to purchase incremental market-priced gas to support these customers.

The Public Staff witnesses noted that the affected customers would pay an additional $1,205,231 for the cost of gas for the month of January. This would equate to $61 per dt, which is almost 11 times the cost of gas supply that Piedmont actually incurred. The Public Staff strongly believes that the interruptible customers who failed to curtail their usage should not be penalized with an exorbitantly high cost of gas that Piedmont did not actually incur as they have already been assessed the Rate Schedule 106 penalty for the specific type of service provided during the curtailment periods.

Piedmont witnesses Yoho and Powers testified that the Company billed the specific customers without applying the commodity index price mechanism because it realized that it could not obtain prior Commission authorization for a waiver of the mechanism without delaying its bills for January service. Because of that, along with the additional fact that the customers owed other charges billed pursuant to Rate Schedule 106, Piedmont believed the more reasonable and orderly approach was to bill first and then seek Commission approval to modify its billing practice in a separate petition so that it could be dealt with in an orderly manner. Piedmont witness Yoho noted that the vast majority of this relatively small volume impacted one customer. Piedmont believed that its circumstances were different than Public Service of North Carolina because the Company did not supply the gas. Witness Yoho opined, therefore, that a gas component was not a reasonable penalty, and further, the more gas on the system during a cold weather event, the better.

Piedmont witness Powers testified that the Company believed that it may have a "hole" in its tariff to the extent it allows a situation like that faced in January 2014, where it does not provide for an explicit exclusion from the commodity index price component of the billing of Emergency Service for those transportation customers who provide their own gas. Piedmont could not think of a reason why those customers should be required to pay exorbitant commodity index prices where (1) Piedmont did not purchase or otherwise supply any commodity in conjunction with Emergency Service to its transportation customers, and (2) charging such a commodity price would serve no other purpose.

The Public Staff witnesses testified that Piedmont did not consult with the Public Staff in January 2014 about the curtailments and some of the customers failing to comply with the curtailments. However, the Public Staff received notices of the curtailments. Piedmont did not consult with the Public Staff prior to billing the customers in February, 2014. The Public Staff did not agree with Piedmont's position that interruptible transportation customers that brought their own gas to the city gates should be exempt from the commodity index pricing mechanism.

The Public Staff agreed that Piedmont should modify its tariff to avoid a reoccurrence of the disparity between the cost of gas actually incurred by the Company and the cost of gas actually incurred by the company. The Public Staff recommended that Rate Schedule 106 be modified to use the highest flowing system gas cost (excluding gas supply assigned to the secondary market) that was incurred during the curtailment event. In that manner, the customer who fails to curtail pays the actual incurred incremental cost. The Public Staff also supported an increased penalty surcharge to deter customers from failing to comply with Piedmont’s curtailment directives.

The Stipulation of Settlement between Piedmont and the Public Staff states that with respect to the billing of the underlying sales and transportation rate under Rate Schedule 104 or 114, respectively, as applied to solely curtailment usage quantities, the Company shall bill such charges with all applicable step rates rather than with only the maximum (first) step rate; and the substitute per dekatherm commodity charge shall also be in lieu of the benchmark cost of gas rate component for Rate Schedule 104, which is applicable to all curtailment usage by curtailed interruptible sales customers. Finally, the Company shall bill the underlying transportation rate using Rate Schedule 114 for all curtailment usage by interruptible transportation customers in all circumstances.

At the hearing, Public Staff witnesses Davis and Perry testified that the Public Staff disagreed with billing the curtailed Rate 114 - Interruptible Transportation customers that took Unauthorized Gas at the Rate 104 - Interruptible Sales Rate. The Public Staff believed that even though Rate Schedule 104 includes a benchmark cost of gas component of $4.25 per dt for January 2014, this rate is not sufficient to cover the cost of gas supply actually incurred by

Piedmont to serve these customers. As a result, an under-collection was reflected in the Sales Customers Only deferred account, which would ultimately be recovered from those customers, causing them to subsidize the cost of gas supplies billed to Rate Schedule 114 customers that took Unauthorized Gas. The Public Staff also disagreed with the billing of the Rate Schedule 104 - Interruptible Sales customers for Emergency Service and Unauthorized Gas taken during the curtailment event under its existing rate schedule because, although Rate Schedule 104 includes a benchmark cost of gas component of $4.25 per dt for January 2014, this rate is not sufficient to cover the cost of gas supply actually incurred and would also result in a recovery from other customers.

In its testimony, the Public Staff took the position that the impacted customers should be re-billed as follows: (1) for all curtailed customers, the volumetric tariff rate for the underlying interruptible sales and transportation rate schedule through all of the applicable step usage rates for the volumes burned during the month instead of only the first step rate; (2) for Rate Schedule 114 customers, Piedmont's highest cost of flowing gas for the month, plus the 100% load factor rate under Transco's currently effective Rate Schedule FT for deliveries from Zone 4 to Zone 5, including applicable fuel retention and surcharges, for a total of $6.2889/dt to more accurately match volumes and prices that would align with the highest flowing gas cost incurred; and (3) for Rate Schedule 104 customers, the additional cost of the highest flowing gas supply above the benchmark cost of gas, since the customers have already been billed at the benchmark for the affected Rate Schedule 104 - Interruptible Sales.

The Public Staff witnesses also testified concerning a similar case involving Public Service Company of North Carolina, Inc. (PSNC) in Docket No. G-5, Sub 545. Both Piedmont and PSNC experienced high demand during January 2014 and issued curtailments of interruptible customers. Compared to Piedmont, PSNC curtailed on a larger scale than Piedmont, notifying all of its 173 interruptible customers to curtail on several days during the month. Due to similarities involving gas index mechanisms in their applicable tariffs, which resulted in significantly high bills to their impacted customers, both companies faced similar issues concerning the prospect of billing directly pursuant to their filed tariffs. PSNC elected to hold billing of its customers and then filed a petition with the Commission requesting relief or guidance from the Commission. In contrast, Piedmont billed within the appropriate time period yet varied from its tariff and then filed its petition seeking modification. As testified to by Piedmont witness Yoho, in an effort to resolve the disputes between the active parties to this proceeding, Piedmont essentially adopted the Public Staff's positions as reflected in the provisions of paragraph 2 of the Stipulation:

A. That a waiver of the commodity index pricing mechanism under Piedmont's Rate Schedule 106 should be granted with respect to Piedmont's curtailed interruptible sales and transportation customers for purposes of billing Emergency Service and Unauthorized Gas during the month of January 2014.

B. That in lieu of the commodity index pricing mechanism under Piedmont's Rate Schedule 106, Piedmont's curtailed interruptible sales and transportation customers who received Emergency Service or who took Unauthorized Gas during January, 2014 should be charged a substitute per dekatherm commodity charge equal to Piedmont's highest flowing gas costs during the month of January, 2014.

C. All other charges applicable to Emergency Service and to Unauthorized Gas volumes under Piedmont's Rate Schedule 106 should be charged to curtailed interruptible sales or transportation customers receiving Emergency Service and taking Unauthorized Gas during January, 2014 as provided for by Rate Schedule 106. With respect to billing of the underlying sales and transportation rate under Rate Schedules 104 or 114, respectively, as applied to solely curtailment usage quantities:

- the Company shall bill such charges with all applicable step rates rather than with only the maximum (first) step rate;

- the substitute per dekatherm commodity charge discussed in paragraph B shall also be in lieu of the benchmark cost of gas rate component for Rate Schedule 104, which is applicable to all curtailment usage by curtailed interruptible sales customers.

- the Company shall bill the underlying transportation rate using Rate Schedule 114 for all curtailment usage by interruptible transportation customers in all circumstances.

D. Piedmont will work with the curtailed interruptible transportation customers who received Emergency Service from Piedmont during January, 2014, and their associated marketers, to give the affected customers credit for gas originally provided by those customers using Piedmont's Rate Schedule 107 end of month cash-out mechanism. Such credits shall be given to those marketers or the affected customers (if that customer did not use a marketer), as applicable, in accordance with Piedmont's approved cash-out procedures prescribed in Rate Schedule 107.

E. Piedmont agrees that it should debit or credit the Sales Customers Only and the All Customers deferred accounts, as appropriate, for the total cost of gas component associated with Emergency Service and Unauthorized Gas as authorized by the Commission, including interest.

F. Piedmont should not be penalized for its conduct in varying from its tariff in this instance as that conduct was solely for the benefit of its customers; provided, however, that Piedmont agrees not to vary from its tariff obligations in the future without seeking prior Commission approval. (emphasis in original)

G. Piedmont and the Public Staff commit to work together going forward in an attempt to develop mutually agreeable revisions to Piedmont's Rate Schedules 106 and 107 to address the situation that led to this docket and to file any such agreed revisions as a supplemental settlement in this proceeding.

The Commission concludes, based on all the evidence, that with the exception of the crediting of gas provided by the customers or their marketers and the acknowledgement that Piedmont shall bill charges according to all applicable step rates rather than at only the first step rate, the tariff modifications proposed by Piedmont and the Public Staff, as set forth in the

Stipulation, represent a departure from the terms of Piedmont's Rate Schedule 106. Pursuant to G.S. 62-130, the Commission is required to approve just and reasonable rates. Once approved in a general rate case, the rates became charges presumed to be just and reasonable, irrespective of what the Commission's intent may have been at the time the rates were approved. G.S. 62-132. In Piedmont's last general rate case, the Commission concluded that Rate Schedule 106 established just and reasonable rates for interruptible customers that choose not to curtail and decided, instead, to use Emergency Service or Unauthorized Gas. The Commission deems it unwise to establish a precedent even in the circumstances presented in this case to modify, for service received in the past, tariffs on the theory that the terms of the tariff fail to comply with representations of the intent purportedly behind unambiguous tariff terms.

General Statute 62-139 provides, in pertinent part:

> No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission, nor shall any person receive or accept any service from a public utility for a compensation greater or less than that prescribed by the Commission.

In the present docket the curtailable and interruptible customers received gas service under Schedule 106 before any modification was requested or addressed. After the service was provided Piedmont and the Public Staff have requested in the Stipulation that the Commission modify Schedule 106 to significantly reduce the cost of gas component charged to interruptible customers in January 2014. Piedmont and the Public Staff are attempting to avoid what they perceive to be unfair rate impacts on interruptible customers resulting from the prolonged periods of cold weather and unusually high spot market gas prices in January 2014.

While, for arguments sake, it may be assumed that during January 2014 the tariffs did not produce charges as anticipated or foreseen, they produced charges according to terms as written and approved. To the extent modifications are justified so that the tariff terms comply with the intent testified to by witnesses in this docket, the Commission concludes that such modifications must be made to affect prospective, not past, gas service. In addition, the Commission concludes that any changes to Piedmont's tariffs should be considered in a docket that provides the Commission with full information and allows the Commission adequate time to review the effects of proposed changes on all of Piedmont's ratepayers, not just its interruptible customers. Accordingly, the Commission will defer its consideration of any changes to Piedmont's tariffs until Piedmont files a request for changes in a separate docket or in a general rate case.

The Commission has given considerable thought to its obligation to approve just and reasonable rates and to require Piedmont to collect those rates according to the terms of Piedmont's tariffs. With regard to Piedmont's interruptible rates, one feature of the cost of gas component of Schedule 106 allows Piedmont to fully recover its cost of gas in providing Emergency Service and Unauthorized Gas to Schedule 106 customers that choose not to curtail their usage when notified to do so by Piedmont. Another equally important feature of the cost of gas component is that it provides an incentive for interruptible customers to curtail their usage when they are notified to do so. After all, that is the single justification for having interruptible rates. Although Emergency

Service is appropriate in some circumstances, it should be the exception rather than the rule. Further, the taking of Unauthorized Gas should be strongly discouraged.

Volatility in the monthly and daily index prices of natural gas has been a common place occurrence and certainly such was the case when the Commission approved Schedule 106 based on the monthly and daily indices. Indeed, the Commission views the probability of price volatility at some point as an inducement for those weighing the advisability of subscribing to interruptible schedules and determining whether to comply with curtailment notices. If an interruptible customer studies, understands and weighs the risk of high gas prices to be paid under the monthly and daily indices, then decides to use Emergency Service or take Unauthorized Gas, that customer has made a knowing and conscious decision to risk the payment of high gas prices rather than to curtail its usage. When that risk materializes into a need to acquire energy service or unauthorized gas, the Commission expects the customer to bear the consequences of its decision and pay the cost of gas according to the tariff.

The Commission is concerned that should it authorize after-the-fact modifications to tariffs in effect when service has been provided in this difficult circumstance, it will set a precedent of questionable legality and one that should be avoided as poor practice.

While the parties contend that equitable relief is justified in these unique circumstances, granting the relief requested has countervailing and adverse consequences to Piedmont customers. The evidence in this docket demonstrates that interruptible customers enjoy substantially lower rates than firm customers. The consideration for those lower rates is the fact that Piedmont can plan and operate its system at a lower capacity, and thus at a lower cost, because it can depend on curtailing its interruptible customers when weather and other events place a strain on the system. However, if interruptible customers are approved to supply their own gas on the system during curtailment and are permitted to ignore curtailment notices and to continue to use gas as if no curtailment has been called by Piedmont, then interruptible customers are receiving service more like that provided to firm customers than interruptible ones, without paying the substantially higher rates that firm customers pay. Further, Piedmont will lose confidence that it can plan its system based on having the ability to curtail interruptible customers.

Moreover, because interruptible customers pay substantially lower rates than firm customers, the Commission is concerned that Piedmont's proposed modification of Schedule 106 may result in firm customers subsidizing interruptible customers. Revenue received by Piedmont under the cost of gas component of Schedule 106 is credited to Piedmont’s Sales Customers Only deferred account and customers on the Sales Customers Only schedules include all residential customers. The Schedule 106 modification requested by Piedmont and supported by the Public Staff would result in Piedmont receiving $1.2 million less from interruptible customers for Emergency Service and Unauthorized Gas in January 2014 than Piedmont will receive if the tariff is enforced as written. As a result, Piedmont's Sales Customers Only deferred account would have a balance that is $1.2 million less than if Schedule 106 is enforced as written.

The testimony of Piedmont's witnesses shows that in the past Piedmont's interruptible customers have enjoyed the advantage of paying substantially lower rates than Piedmont's firm customers, yet have rarely been required to curtail their gas service. In January 2014, when they were notified to curtail, some interruptible customers made a business decision to continue using gas and to pay the tariffed rate for Emergency Service and Unauthorized Gas under Schedule 106. That will result in Piedmont's firm customers receiving some financial offset according to approved tariffs to the higher firm rates they have agreed to pay. Also, it will result in Piedmont's interruptible customers paying the tariffed rates that they agreed to pay when they chose not to curtail their gas usage in January 2014. Further, it will result in Piedmont receiving the proper amount of revenue to be credited to its Sales Customers Only deferred account. Moreover, other customers on Schedule 106 curtailed usage when instructed and accepted the adverse consequences inherent in their earlier decision to subscribe to Schedule 106 and their decision in January 2014 to curtail as instructed. While Piedmont escaped purchasing exorbitantly high-priced gas on the spot market in January 2014, the situation would be different in the future if all the Schedule 106 customers refuse to curtail.

As stated above, the Commission is mindful of the difficulties to which affected interruptible customers are placed by enforcing Piedmont's tariffs as written. Consequently, the Commission finds good cause to provide Piedmont's interruptible customers with a measure of relief by giving them time to pay their January 2014 bills. The Commission concludes that it is appropriate to grant Piedmont's interruptible customers a further extension of time in which to pay the balance owed under Schedule 106 for January 2014. Accordingly, the Commission will direct that Piedmont allow these customers to pay the balance owed under Schedule 106 for January 2014 in equal installments over the next 18 months, beginning on December 1, 2014, without the imposition of late fees or interest so long as the customer makes each installment payment on time. In addition, the Commission will allow Piedmont to negotiate an installment payment arrangement of more than 18 months with any customer that is in a situation that Piedmont deems appropriate for a longer payment plan. However, in those situations the risk of failing to collect the full amount owed by any such customer shall rest with Piedmont. That is, if a customer is given more than 18 months and fails to pay any portion due to Piedmont, then Piedmont shall not be allowed to recover that unpaid balance from Piedmont's ratepayers as an uncollectible expense or as any other cost of service item. By placing this responsibility upon Piedmont the Commission expects the Company to monitor with vigilance the credit worthiness of customers to whom additional extensions are allowed and to impose such reporting requirements as are necessary in exchange for the extensions.

Under the terms of the Stipulation, the parties have requested that the curtailed interruptible transportation customers who received Emergency Service from Piedmont during January 2014, and their associated marketers, be given credit for gas originally provided by these customers using Piedmont's Rate Schedule 107 end of month cash-out mechanism. In order to provide Emergency Service, Piedmont had to secure gas and bring the gas to its system. Clearly, Piedmont would be required to pay for that gas. However, Piedmont required that customers requesting Emergency Service or their marketers bring gas to Piedmont's system. The Commission concludes that Piedmont must bill the customers for the commodity cost of gas pursuant to its tariffs, including billing charges according to all applicable step rates rather than at only the first step rate. Further, it is appropriate for Piedmont to reimburse its interruptible customers, or their marketers, pursuant to Rate Schedule 107 for the gas they brought to the Piedmont system in January 2014.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38-39

The evidence for these findings of fact is contained in the testimony and exhibits of Piedmont witness Powers.

Commission Rule R6-12(2) requires local distribution companies (LDCs) to, "Assist the customer or prospective customer in selecting the most economical rate schedule." However, the chosen rate schedule must also be one for which the customer actually qualifies.

Piedmont's cheapest sales rates are its Rate Schedule 104 - Interruptible Sales and the corresponding transportation tariff, Rate Schedule 114. To qualify for Rate 104 and 114, a customer's average daily gas usage must be "reasonably anticipated to equal or exceed 50 dekatherms per day." Per Commission Rule R6-12(7), each summer Piedmont is required to review the consumption for each qualifying customer for the twelve months ending June 30 of the past two years and:

> If it is found that the customer has either increased or decreased his annual consumption based on the two prior years' consumption to the point it would place him on a different rate schedule, the customer shall be automatically reclassified to the proper rate schedule effective the following September 1. In determining consumption, periods of involuntary curtailment shall be excluded.

The tariff for Rate Schedule 104 explicitly states, "All gas delivered pursuant to this Rate Schedule shall be metered by the Company separately from any gas delivered to Customer under any of the Company's other Rate Schedules." Rate Schedule 104 is subject to curtailment pursuant to Piedmont's Rate Schedule 106, which states in part, "Service provided under any Rate Schedule where the character of Service is designated as 'interruptible' may be interrupted or Curtailed by the Company at any time and for any reason deemed necessary or appropriate by Company."

If a customer is not fully capable of being curtailed, then the customer does not qualify for an interruptible rate, irrespective of whether that is the "most economical rate schedule" for that customer. In addition, if a customer is not fully curtailable because it requires natural gas for such uses as space heating, then it is likely that the cost of Unauthorized Gas to meet those needs could render Piedmont's interruptible schedules not the "most economical" for that customer when Piedmont notifies customers of a curtailment.

If a customer seeking service under Rate Schedule 104 wants gas on a firm basis for some need such as space heating, (1) it must purchase that gas under a more expensive rate schedule and, (2) it may not count volumes consumed under the more expensive rate schedule towards its 50 dts per day requirement to qualify for Rate Schedule 104.

According to Powers Exhibit No. 2, several customers failed to curtail because they wanted to continue to use natural gas for such uses as space heating or keeping boilers warm. For volumes needed for such uses, the Commission is of the opinion that these customers should have been on a firm rate. Also, the Commission concludes that such volumes should not have gone toward their 50 dts per day total.

There are significant differences in rates between Piedmont's Rate Schedule 104, and corresponding transportation Rate Schedule 114, and its firm Large General Sales Service under Rate Schedule 103, and corresponding transportation Rate Schedule 113. Furthermore, there are significant differences in rates between the rates in Rate Schedule 103 and Piedmont's Medium General Service rates under Rate Schedule 152 and Small General Service rates under Rate Schedule 102. These differences create a strong incentive for customers to assert that they are prepared to curtail when they in fact cannot. To allow some customers to receive the benefit of a large-volume, interruptible rate when they are not, in fact, willing to curtail when called upon to do so creates a situation that is inherently unfair to other customers.

The Commission recognizes that there may be customers dependent on natural gas for such uses as space heating who are willing to curtail when called upon to do so. However, based on the evidence in this docket, the Commission is concerned that there may be Piedmont interruptible customers receiving natural gas on a firm basis for space heating and other uses that should be provided under a firm service rate. Therefore, the Commission concludes that there is good cause to require that Piedmont engage in a comprehensive review of the Emergency Service and Unauthorized Gas used during January 2014, as well as Piedmont's previous customer consumption records, and determine whether there are interruptible customers receiving natural gas for space heating and other uses that should be provided under a firm service tariff.

If it is determined that a customer needs a separate meter for firm use, the Commission recognizes that it takes time and effort to switch a customer from interruptible to firm rates. Therefore, the Commission expects Piedmont to take the necessary time to conduct the required analysis and to add the upstream capacity, if necessary, before removing customers from the interruptible tariff and requiring that they take service under a firm rate. The Commission concludes that Piedmont shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its investigation of this matter and stating all actions that Piedmont has taken and will take within its ability and authority to ensure that its customers are receiving service under the appropriate tariff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 40-45

The evidence for these findings of fact is contained in the testimony of Piedmont witnesses Yoho and Powers, in the Company's exhibits, and in the joint testimony of Public Staff witnesses Davis and Perry.

There is no disagreement among the parties about the actual amounts that were billed by Piedmont for service provided in January 2014. The testimony and exhibits indicate that Piedmont varied the rates approved under Schedule 106 for Emergency Service and Unauthorized Gas provided to customers in two respects. First, Piedmont did not charge the cost of gas component of Schedule 106 to those interruptible transportation customers that brought their own gas to Piedmont's city gate. Second, in the instances in which Piedmont did charge a cost of gas component for Emergency Service and Unauthorized Gas, Piedmont charged a reduced rate of $ 4.25 per dt, rather than the higher of the two index rates specified in Schedule 106.

The details of Piedmont's first variance from the tariff are fully discussed under the evidence and conclusions for Findings of Fact Nos. 22-37. In summary, even though Piedmont had called for curtailments Piedmont encouraged its interruptible transportation customers that requested Emergency Service to have their marketers deliver the customers' gas to Piedmont's city gate. Piedmont witnesses Powers and Yoho testified that for interruptible transportation customers receiving service under Schedule 114, Piedmont conditioned the approval of Emergency Service on the delivery by those customers of the underlying quantities of gas to Piedmont at its city gate delivery points. As a result, all Emergency Service gas provided to Piedmont's transportation customers was provided using gas supplied by those customers. In her rebuttal testimony, Piedmont Witness Powers testified that this circumstance had not occurred in prior curtailment events where Piedmont provided Emergency Service. Piedmont witness Yoho testified in his rebuttal testimony that the Emergency Service provided in January 2014 was fundamentally a transportation service whereas the underlying presumption of Rate Schedule 106 is that it is a sales service. He further opined that the increased gas brought on to the Piedmont system during the severe weather events was beneficial to the high demand requirements of the system and to all customers.

Piedmont witness Powers testified that the Company believed that it may have a "hole" in its tariff to the extent it allows a situation like that occurring in January 2014, where the tariff does not provide for an explicit exclusion from the commodity index price component of the billing of Emergency Service for those transportation customers who provide their own gas. Piedmont could not think of a reason why those customers should be required to pay exorbitant commodity index prices where (1) Piedmont did not purchase or otherwise supply any commodity in conjunction with Emergency Service to its transportation customers, and (2) charging such a commodity price would serve no other purpose. Therefore, according to witness Powers, Piedmont billed interruptible transportation customers receiving Emergency Service (1) the underlying Schedule 114 first step usage rate, and (2) the premium/penalty rate of $10 per dt specified under Schedule 106. Witness Powers stated that Piedmont did not bill these customers the index price component specified under Schedule 106. These facts are substantiated in witness Power's Revised Exhibit PKP-3, which includes the details of Emergency Service and Unauthorized Gas usage by curtailed customers, the amounts billed for such usage by Piedmont, and the amounts that would have been billed by Piedmont if it had billed according to the terms of Schedule 106.

Public Staff witnesses Davis and Perry did not agree with Piedmont's position that interruptible transportation customers that brought their own gas to Piedmont's city gate should be exempt from paying a cost of gas component under Schedule 106. Indeed, they testified that the Public Staff's position is that once an interruptible transportation customer requests Emergency Service or uses Unauthorized Gas that customer becomes a sales customer under Schedule 106. Further, the Public Staff witnesses testified that in the past Piedmont has consistently billed Emergency Service and Unauthorized Gas in compliance with Schedule 106. The Public Staff witnesses agreed with Piedmont that applying the Schedule 106 cost of gas index rates for gas received during the curtailment events in January 2014 would be financially burdensome to the affected interruptible customers. However, they stated that those customers should pay a cost of gas component based on Piedmont's highest cost flowing gas during January 2014, and that the payment of some amount as a cost of gas component would be more consistent with the structure of Schedule 106.

In response to questions from the Commission Staff, Piedmont witness Yoho agreed that it is the Commission's authority and role to set the rates charged by the public utilities that the Commission regulates. Further, witness Yoho acknowledged that it is the Commission's authority and role to determine what rates are just and reasonable, and that Piedmont does not have that authority. Moreover, witness Yoho agreed that in Piedmont's last general rate case the Commission determined that the rates fixed in Schedule 106 are just and reasonable, and that if Piedmont disagreed with that determination it had the right to appeal or request reconsideration.

In response to questions from the Commission, Piedmont witness Yoho agreed that there is no ambiguity in Schedule 106, although he qualified his answer by stating that changes in the energy industry could create ambiguous circumstances.

In further response to questions from the Commission, witness Yoho testified:

> I believe we, with the status of the emergency sales and unauthorized, we should have billed according to tariff and we did not.

T, at p. 152.

Notwithstanding changes in the energy industry and the prolonged periods of cold weather in January 2014, the Commission concludes that there is no ambiguity in Schedule 106. The plain language of the tariff requires Piedmont to charge interruptible customers two charges for Emergency Service: (1) a penalty of $10 per dt, and (2) a cost of gas charge equal to the higher of the two indices specified in the tariff. The same is true of the charges for Unauthorized Gas under Schedule 106, except that the penalty component is $25 per dt.

Based on a preponderance of the evidence before the Commission in this docket, and the reasonable inferences from the evidence, the Commission concludes that Piedmont knowingly and intentionally charged and received a lesser rate than that required under Schedule 106, in two respects. First, Piedmont did not charge the cost of gas component of Schedule 106 to those interruptible transportation customers receiving Emergency Service if the customer brought its own gas to Piedmont's city gate. There is no language in Schedule 106 that relieves an interruptible transportation customer from paying the cost of gas component when the customer provides its own gas, or for any other reason. Piedmont witness Yoho attempted to justify Piedmont's failure to charge the cost of gas component by contending that such a charge would result in double billing of those interruptible transportation customers for the gas they received. However, Public Staff witness Davis explained that marketers tend to bring the gas in pools and it is difficult to determine on a particular day or at a particular time which customer is receiving what quantity of gas from the pool. However, there is a balancing or “cash out” at the end of each month. Each customer is given a credit for gas that was brought to the system for the customer but was not used by that customer.

The second instance in which Piedmont charged a lesser rate than that required under Schedule 106 occurred when Piedmont charged a cost of gas component for Emergency Service and Unauthorized Gas that was not the cost of gas component specified under Schedule 106.

Piedmont charged a reduced rate of $4.25 per dt, rather than the higher of the two market index rates specified in Schedule 106.

The $4.25 per dt charged by Piedmont was Piedmont's benchmark cost of gas during January 2014. However, there is nothing in Schedule 106 that authorizes Piedmont to substitute its benchmark cost of gas for the index prices that are so clearly spelled out in Schedule 106. The Commission appreciates Piedmont's concern that the index prices in January were unusually high and might create a hardship on Piedmont's customers. Nevertheless, the purpose of a tariff is to set rates and conditions for utility service. Schedule 106 does that in a clear and unambiguous manner. Therefore, the Commission expects Piedmont to bill and collect the amount specified under the tariff.

Piedmont witnesses Yoho and Powers testified that the Company billed its interruptible customers without applying the Schedule 106 commodity index price mechanism because it realized that it could not obtain prior Commission authorization for a waiver of the mechanism without delaying its bills for January service. Because of that, along with the additional fact that the customers owed other charges billed pursuant to Schedule 106, Piedmont believed the more reasonable and orderly approach was to send the bills in February and then seek Commission approval to modify its Schedule 106 billing in a separate petition. In addition, Piedmont believed that its circumstances were different than that of Public Service of North Carolina because Piedmont did not supply the Emergency Service gas. Further, Piedmont operated under the belief that the more gas on the system during a cold weather event, the better.

Public Staff witnesses Davis and Perry testified that Piedmont did not consult with the Public Staff in January 2014 about the curtailments and the failure of some customers to comply with the curtailments. However, the Public Staff received notices of the curtailments. In addition, the Public Staff witnesses testified that Piedmont did not consult with the Public Staff prior to billing the interruptible customers for Emergency Service and Unauthorized Gas in February 2014.

In the Joint Stipulation of Settlement between Piedmont and the Public Staff, Paragraph F, the parties' state:

> Piedmont should not be penalized for its conduct in varying from its tariff in this instance as that conduct was solely for the benefit of its customers; however, that Piedmont agrees not to vary from its tariff obligations in the future without seeking <u>prior</u> Commission approval. (emphasis in original)

Public Staff witnesses Davis testified that based on his more than 20 years with the Public Staff he could not recall an instance in which a public utility regulated by the Commission unilaterally modified a rate in this manner. Witness Davis stated:

> It usually would involve a step where there would be a request for a waiver before implementation.

T, at p. 221.

The Commission appreciates Piedmont's concern about getting its January 2014 bills out on time, its concerns for its customers, and its willingness to abide by its tariffs in the future. Nevertheless, the Commission cannot overlook the fact that Piedmont failed to bring this situation to the attention of the Commission before taking action to vary the terms of the Company's tariff. The Commission finds Piedmont's actions particularly perplexing in light of the course followed by Public Service of North Carolina (PSNC) when PSNC was faced with the same dilemma in February 2014. On February 19, 2014, in Docket No. G-5, Sub 545, PSNC filed a petition requesting a modification of its interruptible tariff, Rider A, for Emergency Service and Unauthorized Gas provided to customers during January 2014. On March 6, 2014, the Commission issued an order that directed PSNC to bill the full amount owed under the terms of Rider A, but allowed customers to pay, on an interim basis, the modified Rider A amount requested by PSNC. Part of the Commission's thinking was that it would be useful for interruptible customers to see on their bill the total amount owed under PSNC's Rider A. The same would have been true with regard to Piedmont's interruptible customers. Nevertheless, Piedmont's act of unilaterally modifying Schedule 106 and sending bills on February 5, 2014, without any notice to the Commission, denied the Commission the opportunity to address these issues in a more orderly fashion. One consequence of Piedmont's precipitous actions is that its interruptible customers will now for the first time receive a bill for the full cost of the service that they received some nine months ago, in January 2014.

The Commission concludes that Piedmont should be penalized for its failure to bill and collect according to Schedule 106 because Piedmont's knowing and intentional acts were in violation of G.S. 62- 139(a), which provides, in pertinent part:

> No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission…

In addition, pursuant to G.S. 62-310(a)

> Any public utility which violates any of the provisions of this Chapter or refuses to conform to or obey any rule, order or regulation of the Commission shall, in addition to the other penalties prescribed in this Chapter forfeit and pay a sum up to one thousand dollars ($1,000) for each offense, to be recovered in an action to be instituted in the Superior Court of Wake County on the relation of the Utilities Commission; and each day such public utility continues to violate any provision of this Chapter or continues to refuse to obey or perform any rule, order or regulation prescribed by the Commission shall be a separate offense.

In an analogous situation, the Public Staff filed a Petition for Order to Show Cause against AT&T Communications of the Southern States, LLC (AT&T) in Docket No. P-140, Sub 79. The evidence showed that AT&T was involved in a disagreement with Madison River Communications, LLC (MRC) regarding access service being provided by MRC to AT&T's long-distance customers. AT&T was unable to resolve the dispute to its satisfaction and, therefore, instructed MRC to cease providing long-distance access services to AT&T's customers. MRC initially refused to cease providing long-distance access services to AT&T's customers and attempted to resolve the dispute with AT&T. However, when it was unable to do so, MRC followed AT&T's instructions and ceased routing calls by AT&T's long-distance customers on MRC's system. The Public Staff asserted that AT&T's directive to MRC, and MRC's ultimate compliance with the directive, constituted a violation by AT&T of G.S. 62-118(a), among other statutes, because AT&T had reduced services to its customers without Commission authorization. The cessation of service to AT&T's customers lasted 62 days and affected 14 AT&T customers. In a Recommended Order Finding Violations and Imposing Penalty, a majority of the Commission panel agreed with the Public Staff and imposed a penalty of $50,000 pursuant to G.S. 62-310(a). The Recommended Order discusses the calculation of penalties under G.S. 62-310(a) and notes that the Public Staff could have recommended a penalty based on 14 violations a day for 62 days, a total penalty of $868,000 for the violations of G.S. 62-118(a). Commissioner Ervin dissented; stating that he did not believe that the evidence was sufficient to show that MRC's actions in ceasing to serve AT&T's customers were directly attributable to AT&T. AT&T filed exceptions and requested a review by the full Commission. The full Commission affirmed the panel's Recommended Order, although it reduced the penalty to $25,000. Order Overruling Exceptions and Reducing Penalty, Docket No. P-140, Sub 79, February 5, 2003 (Commissioners Ervin and Kerr dissenting).

As in the AT&T docket, the purpose of the penalty to be assessed against Piedmont is to deter future violations of G.S. 62-139(a) or unilateral variances from the Company's approved tariffs. Based on a preponderance of the evidence and in accordance with the provisions of G.S. 62-310(a), the Commission concludes that Piedmont was in violation of Schedule 106 each day from February 5, 2014, when it billed 26 customers unauthorized amounts for service in January 2014, until April 11, 2014, when Piedmont requested authority from the Commission to modify its Schedule 106 bills for service provided in January 2014. Thus, Piedmont was in violation of its tariff for 65 days. In addition, each of the 26 bills that Piedmont sent to its interruptible customers that omitted charges for Emergency Service gas under Schedule 106 or included incorrect charges for Unauthorized Gas was a separate offense. Thus, there were 26 separate offenses for each day of the 65 day period. Therefore, pursuant to G.S. 62-310(a) the Commission could charge Piedmont a penalty of $26,000 per day for 65 days, a total of $1,690,000. However, the Commission concludes that a more appropriate penalty is $1,000 per day for each of the 65 days, for a total penalty of $65,000.

IT IS, THEREFORE, ORDERED as follows:

1. That the Joint Stipulation of Settlement between Piedmont and the Public Staff is not approved.

2. That Piedmont's request to implement the billing modifications as set forth in the Stipulation for the affected interruptible customers is denied. However, customers shall be allowed to pay the additional amount owed in equal installments during the 18 month period beginning on December 1, 2014, and ending on May 31, 2016, without the imposition of a late fee or interest charge, so long as all installment payments are made on time. In addition, Piedmont shall be allowed to negotiate an installment payment arrangement of more than 18 months with any customer that is in a situation that Piedmont deems appropriate for a longer payment plan. Further,

Piedmont may include the payment of interest in a negotiated payment plan beyond the initial 18 month period, if deemed appropriate by Piedmont. However, in those situations the risk of failing to collect the full amount owed by any such customer shall be on Piedmont. Thus, if a customer is given more than 18 months and fails to pay any portion due to Piedmont, then Piedmont shall not be allowed to recover that unpaid balance from Piedmont's ratepayers as an uncollectible expense or as any other cost of service item.

3. That Piedmont shall engage in a person-to-person discussion with the appropriate manager or decision maker of each public service entity presently being served under an interruptible tariff. Piedmont shall fully explain the curtailment obligation of such customers, the consequences of choosing to not curtail, the cost of gas under the Schedule 106 indices, and give each customer a copy of this Order. Further, Piedmont shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its person-to-person discussion with the appropriate manager or decision maker of each public service entity and stating whether that customer has decided to continue receiving service under an interruptible tariff.

4. That Piedmont shall conduct an investigation to determine whether there are interruptible customers receiving natural gas on a firm basis for space heating and other uses that should be provided under a firm service tariff. Piedmont shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its investigation of this matter and stating all actions that Piedmont has taken and will take within its ability and authority to ensure that its customers are receiving service under the appropriate tariff.

5. That within thirty (30) days after the date of this Order Piedmont shall pay to the Chief Clerk a penalty in the amount of Sixty-Five Thousand Dollars ($65,000) by check made payable to the North Carolina Department of Commerce – Utilities Commission.

6. That no part of the penalty assessed against Piedmont in this proceeding shall be recovered from Piedmont's customers.

ISSUED BY ORDER OF THE COMMISSION.
This the _29th_ day of October, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. G-5, SUB 545

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Public Service Company of North Carolina, Inc. for Limited Modification of Rider A and Request for Expedited Decision	))))	ORDER ON PETITION FOR LIMITED MODIFICATION OF RIDER A AND REQUEST FOR EXPEDITED DECISION

HEARD: Tuesday, May 6, 2014, at 9:30 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

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For the Using and Consuming Public:

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For the North Carolina Utilities Commission:

Len Green, Senior Staff Attorney, North Carolina Utilities Commission, 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina 27603

BY THE COMMISSION: On February 19, 2014, Public Service Company of North Carolina, Inc. (PSNC or Company), filed a petition pursuant to G.S. 62-139 and Commission Rule R1-5 for a limited modification of paragraph 5 of Rider A of its tariffs, Curtailment of Service Under Commission Rule R6-19.2 and Emergency Services (Rider A), to adjust the calculation of the cost of gas provided under that rider during the month of January 2014 so that customers that did not curtail their gas usage when notified to do so and received Emergency Service or Unauthorized Gas will be allowed to pay $6.3397 per dekatherm (dt) for the Emergency Service and Unauthorized Gas consumed, instead of the higher amounts determined under Rider A. In support of its petition, PSNC noted that, throughout the month of January 2014, North Carolina experienced several prolonged periods of extremely cold weather conditions, which created an unusual situation that justified some measure of relief for Rider A customers that received Emergency Service or Unauthorized Gas during the month. Due to the Company's need to promptly bill its customers for service rendered, PSNC requested that the Commission give expedited consideration to its petition.

On March 3, 2014, PSNC's petition was presented to the Commission at its Regular Staff Conference. The Public Staff stated that it reviewed the petition and recommended approval as filed. The Public Staff further recommended that PSNC be required to file with the Commission, within 90 days after the issuance of an order allowing the limited modification of Rider A, proposed changes to its tariffs that will enable the Company to avoid similar situations in the future. The Commission asked numerous questions of the Public Staff and PSNC, but decided to take the matter under further advisement before rendering a decision.

On March 6, 2014, the Commission issued an Order Allowing Modified Billing of Rider A Customers Pending Hearing on Petition (March 6, 2014 Order) in which the Commission determined that it needed additional information before rendering a decision on the modification of Rider A and would therefore schedule an evidentiary hearing in this docket. As clarified by the Commission's Order dated March 7, 2014, the Order directed PSNC to bill its Rider A customers for the full amount of the Rider A assessments and cost of gas consumed in January 2014, but further directed PSNC to notify Rider A customers that received Emergency Service or Unauthorized Gas in January 2014 that it would accept, on an interim basis until further order by the Commission, payment for Emergency Service and Unauthorized Gas at the rate of $6.3397/dt, subject to the customer paying, without late fees or interest, the additional amount calculated under the Rider A cost of gas formula if the Commission denies PSNC's petition or grants it only in part. In addition, PSNC was directed to file with the Commission within 90 days proposed changes to its interruptible service tariffs that will enable the Company in the future to avoid situations similar to those that occurred in January 2014.

On March 14, 2014, the Commission issued its Order Scheduling Hearing and Requiring Customer Notice. This Order established a hearing date of Tuesday, May 6, 2014, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter. This Order also required PSNC to provide additional information requested by the Commission (described in Attachment A of the Order) as part of its pre-filed testimony. In addition, on March 19, 2014, the Commission issued its Order Requiring Additional Information from PSNC and required PSNC to include the foregoing additional information in its pre-filed testimony.

On April 14, 2014, PSNC filed the direct testimony and exhibits of George B. Ratchford, Vice President – Gas Operations, and Rose M. Jackson, General Manager – Supply and Asset Management. PSNC also filed the additional information requested by the Commission in the March 14 Order. On April 23, 2014, PSNC filed a corrected Exhibit 4 to the testimony of witness Jackson.

On April 28, 2014, the Public Staff filed the joint direct testimony and exhibits of Jeffrey L. Davis, Director, Natural Gas Division, and Julie G. Perry, Supervisor of the Natural Gas Section, Accounting Division (Public Staff witnesses).

On May 5, 2014, PSNC filed the rebuttal testimony of Candace A. Paton, Rates and Regulatory Manager.

On May 6, 2014, the matter came before the Commission as scheduled and all prefiled testimony and exhibits were admitted into evidence. The PSNC and Public Staff witnesses all testified at the hearing. No public witnesses appeared at the hearing. Prior to the hearing, however, the Public Staff received and filed with the Commission numerous letters and emails from PSNC's industrial customers supporting the Company's petition in this docket.

On May 15, 2014, the Commission issued its Order Requiring Supplemental Exhibit, which directed PSNC to supplement Exhibit 1 to PSNC witness Jackson's testimony by providing the cost of delivered gas for the eight days in January 2014 not included in the original exhibit. PSNC filed the supplemental exhibit on May 19, 2014.

On June 4, 2014, PSNC filed its Petition to Amend its Tariff, pursuant to the Commission's March 6, 2014 Order.

On June 25, 2014, the Proposed Order of PSNC and the Proposed Order of the Public Staff was filed.

On July 9, 2014, the Commission issued its Order Requiring Late Filed Exhibit which required the Public Staff to provide the actual numbers, calculations, averages, and assumptions used in arriving at the $6.0680/dt conclusion. Public Staff filed the Late Filed Exhibit on July 15, 2014.

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 more than 500,000 winter-peak customers in the State of North Carolina.

2. PSNC is engaged in providing natural gas service to the public and is a public utility as defined in G.S. 62-3(23), subject to the jurisdiction of this Commission.

3. PSNC plans and operates its system to serve firm customers on a design day.

4. PSNC's ability to curtail interruptible customers on the day of very high demand allows it to avoid the costs of building the capacity that would be needed to serve those customers on such a day.

5. Interruptible customers pay substantially lower rates than firm customers in exchange for agreeing to curtail.

6. During January of 2014, prolonged periods of cold weather were experienced in PSNC's service territory.

7. As of January 2014, PSNC had 173 accounts served under an interruptible rate schedule, 7 of which were on Rate Schedule 150 (Interruptible Sales Service) and the remaining 166 of which were on Rate Schedule 180 (Interruptible Transportation Service).

8. During January 2014, PSNC issued curtailment notices covering all or a portion of 23 days in the month (curtailment days). Each of PSNC's 173 interruptible customers was subject to one or more of these curtailment notices.

9. PSNC issued curtailment notices to its interruptible customers during January 2014 in an effort to preserve its ability to serve its firm customers.

10. Many of the interruptible customers subject to curtailment did not fully curtail their usage on curtailment days during January 2014.

11. Peaking assets were utilized by PSNC to serve firm and interruptible customers on curtailment days.

12. Any customer that did not fully curtail its usage utilized Emergency Service, On-Peak (or Limited) Emergency Service, or Unauthorized Gas pursuant to PSNC's Rider A tariff.

13. PSNC had 92 customers that took either On-Peak Emergency Service, Limited Emergency Service or Unauthorized Gas during January 2014.

14. PSNC's tariffs provide that interruptible customers subject to curtailment that do not curtail their usage as directed must pay for the cost of gas used based on the highest of two index prices (Rider A indices) referenced in Rider A.

15. The Rider A tariff consists of a penalty component and a cost of gas component.

16. PSNC appropriately billed the customers that took Emergency Service, On-Peak Service, and Unauthorized Gas, the applicable penalty component.

17. Due to extreme spikes in the daily price of delivered gas during January 2014, the Rider A cost of gas according to the Rider A indices ranged from a low of approximately $4.98 per dekatherm to a high of $136.00 per dekatherm.

18. PSNC and the Public Staff proposed to modify the cost of gas component of Rider A by billing customers that failed to interrupt PSNC's highest cost of flowing gas in January 2014.

19. Modification of the Rider A cost of gas component for January 2014 using PSNC's highest cost of flowing gas in January 2014 is not justified by the weather and gas index pricing circumstances in January 2014. The proposed modification of the cost of gas component would not result in just and reasonable rates for all PSNC customers during January 2014.

20. All of the curtailed customers that continued to take gas as either Emergency Service or Unauthorized Gas did so using PSNC's system supply.

21. PSNC did not purchase any of the high priced delivered gas during the month of January 2014.

22. PSNC appropriately credited the All Customers Deferred account for the penalty component of the Emergency Service and Unauthorized Gas billings in the amount of $1,741,200.

23. If the Commission accepted PSNC's proposed modification of Rider A for January 2014, PSNC would bill its interruptible customers that failed to curtail their usage $3,841,486.81 less than it would bill those customers under Rider A as approved by the Commission.

24. PSNC did not fully comply with Commission Rule R6-12(2) with regard to some interruptible customers that did not curtail.

25. It is appropriate to decline PSNC's request for changes to its Rider A tariff in this docket.

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

These findings are essentially informational, procedural, or jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records or provided in the testimony of PSNC witness Ratchford and the Public Staff witnesses.

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

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Jackson and Ratchford.

PSNC witness Jackson testified that PSNC plans the capacity of its system based on the projected design day demand of the firm customers. She agreed that if PSNC has the ability to cease serving a customer on the day of very high demand, then it can avoid building the capacity needed to serve that particular customer. Witness Jackson and witness Ratchford both testified that building additional capacity would increase PSNC's costs and result in higher rates to PSNC's customers.

PSNC witness Ratchford testified that Rider A has been available to interruptible customers since approximately 1986. The Public Staff witnesses testified that the current version of Rider A was proposed by PSNC in PSNC's 2008 general rate case in Docket No. G-5, Sub 495.

The PSNC witnesses testified that large customers subscribe to interruptible service because they receive lower rates in exchange for taking the risk of being interrupted. The PSNC witnesses were shown a cross-examination exhibit that included calculations demonstrating that under PSNC Rate Schedule 180 – Interruptible Transportation, PSNC's interruptible transportation customers pay 13.95% less for the first 15,000 therms than firm customers pay for the first 15,000 therms under PSNC Rate Schedule 175 – Firm Transportation. The witnesses agreed that this is an accurate calculation of the difference in PSNC's interruptible and firm transportation rates at that level of usage. They also agreed that an interruptible rate that is 13.5% lower than the firm rate for the same level of therms is a substantially lower rate.

The Commission has performed the same calculation and comparison as described above with respect to the usage of 45,000 therms under PSNC Rate Schedule 180 – Interruptible Transportation and PSNC Rate Schedule 175 – Firm Transportation. The result shows that interruptible transportation customers pay 26.9% less for the first 45,000 therms under PSNC Rate Schedule 180 – Interruptible Transportation than firm customers pay for the first 45,000 therms under PSNC Rate Schedule 175 – Firm Transportation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the testimony of PSNC witnesses Jackson and Ratchford.

PSNC witness Jackson testified to extraordinary cold and to the unusual weather pattern of the “Polar Vortex.” Witness Ratchford stated that there were several times in January 2014 when the temperature remained below freezing for two or three successive days.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 - 10

The evidence for these findings of fact is contained in the testimony of PSNC witness Ratchford and the Public Staff witnesses.

PSNC witness Ratchford testified that the Company initiated eleven different curtailments during January 2014 based largely on weather conditions. He noted that there were a few customers curtailed as a result of a transmission line rupture near Asheville. Customers were released from these curtailments when PSNC determined that system conditions, expected weather, and other factors warranted it. All of PSNC’s 173 interruptible customer accounts were subject to curtailment during periods covering January 6 to 8 and January 28 to 30 and fewer customers were curtailed for several other periods during this same month. Witness Ratchford provided details of the various curtailments in Exhibit 2 to his testimony, including the date and time of issuance, beginning and ending date and time, and the number of customers affected. Witness Jackson provided on Exhibit 1 that there were 23 days in the month in which PSNC curtailed all or a portion of those days.

Witness Ratchford also testified that many of the Company’s interruptible customers did not curtail their usage at one time or another during the January 2014 curtailments. There were 173 accounts served under an interruptible schedule with 7 on Rate Schedule 150 (Interruptible Sales Service) and 166 on Rate Schedule 180 (Interruptible Transportation Service). Of the 173 interruptible customer accounts that were directed to curtail, 92 utilized gas at some point during a curtailment period. For the entire month, the total amount of gas used by curtailed customers during curtailment was approximately 77,000 dts. Witness Ratchford further testified that most of the customers that did not curtail did so because of problems with obtaining backup fuel or mechanical problems with backup fuel equipment. He added that approximately 30 of the interruptible customers that took gas while curtailed took gas only for pilot light use but exceeded the 10 therms allowed by the tariff for pilot light use.

PSNC witness Ratchford testified that the Company’s decision to curtail all or a subset of PSNC's interruptible customers was mostly based upon projected high firm customer demands during several prolonged periods of extremely cold weather conditions. Further, PSNC needs interruptible customers to curtail in order that firm customers’ service will not be impaired.

Witness Ratchford testified that once the Company realized that a significant number of customers were not curtailing as notified to do, PSNC had internal discussions with its account representatives reminding them of the requirements contained in Rider A. Account representatives reiterated to some of PSNC’s interruptible customers that if they continued to use natural gas they would be charged according to Rider A terms. Witness Jackson added that, later in the month, when customers were curtailed, they were reminded that if they utilize natural gas while curtailed, they are subject to the unauthorized gas provision in Rider A.

PSNC witness Jackson testified that the poolers (marketers) on PSNC’s system are required to give interruptible customers 48 hours notice of any nomination change. She further explained that when PSNC initiated the curtailments, especially for those two periods where they curtailed every interruptible customer on the system, PSNC allowed poolers to make a day-ahead adjustment or an adjustment 24 hours prior to the gas day. Witness Jackson testified that in the event that PSNC had curtailed a customer, any gas that was brought to the system on that day before a nomination change could be made, went into the poolers' ending balance. She also explained that the poolers’ ending balance would be adjusted depending on whether the poolers were short going into the curtailment or long going into the curtailment. She further testified that the volume of natural gas burned by the customers during the curtailment periods was subtracted from the poolers ending balance at the end of the month. She stated that billing each individual pooler, net of the curtailed volumes, ensures the customer is not billed twice.

Witness Jackson confirmed that it was possible for an interruptible customer or a pooler to re-sell gas the customer originally purchased during a curtailment event. She testified that this was a concern to PSNC but that she was not aware of any gas that was diverted and resold during January 2014. She testified that “right now the only tool that PSNC has to ensure that interruptible customers will not use gas -- or the biggest deterrent we have is curtailment.” She further testified that “on those two extreme cold periods, that's why we had to curtail all of our interruptible customers, because there is no provision in the existing tariff that would prevent or deter a pooler from moving that gas away.” She further stated that termination of pooling agreements was the only tool PSNC presently has to ensure that the pooler or marketer will not move gas away from PSNC’s city gate during a curtailment event. Based on the foregoing testimony, the Commission concludes that PSNC appropriately issued curtailment notices to its interruptible customers in accordance with its tariffs as warranted by the January 2014 weather conditions to preserve its system integrity. The Commission further concludes that PSNC provided Emergency Gas to a substantial number of its interruptible customers and that many of PSNC's interruptible customers used Unauthorized Gas.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is found in the testimony of PSNC witnesses Ratchford and Jackson.

Witness Ratchford testified that gas from system supply was the source of gas used by the customers that did not curtail. He also testified that at any given point in time, system supply may include flowing gas, interstate pipeline storage, line pack, or on-system liquefied natural gas. While witness Ratchford drew a distinction between "flowing gas" and LNG facilities, witness Jackson testified that, in determining the highest cost of flowing gas during the month, PSNC, "actually went back to the monthly cost of gas reporting and journal entries that we book on a monthly basis and then looked at every purchase that was made for PSNC during the month of January." She stated that "purchases" included first of the month purchases, spot market purchases, withdrawals from storage, and withdrawals from the Cary LNG plant.

Witness Jackson stated that, while PSNC did purchase spot gas, "all of these purchases were delivered to PSNC's system using available interstate capacity. Accordingly, PSNC managed to avoid purchasing uncharacteristically high-priced delivered natural gas in order to supply system needs on the days of curtailment."

Witness Jackson testified that, during January 2014, the Company used the peaking facilities at its on-system LNG plant located in Cary, North Carolina, in addition to peaking services that it subscribes to on two interstate pipeline companies regulated by the Federal Energy Regulatory Commission (FERC) - Pine Needle LNG Company, LLC (Pine Needle) and Dominion Cove Point LNG, LP (Cove Point). However, she stated that peaking facilities were not dispatched to serve interruptible customers. While LNG was dispatched on days on which curtailment occurred and interruptible customers did not curtail, she testified that decisions regarding the dispatch of peaking facilities were made to serve projected firm loads. Witness Ratchford also testified that peaking assets were not dispatched to serve firm customers.

The Commission recognizes that the operating decisions to dispatch peaking assets were made based on system conditions and forecasts of demand, and not specifically to meet the needs of interruptible customers. However, as interruptible customers continued to fail to curtail, it would appear that the practical result was that peaking assets went to support interruptible customers. Witness Ratchford testified that "If we incur localized pressure problems based on an interruptible load, we still have the ability to go out and physically valve them off." PSNC did not take that step.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 - 23

The evidence for these findings of fact is found in the testimony of PSNC witnesses Ratchford and Jackson and the joint testimony of the Public Staff witnesses.

PSNC witness Ratchford testified that PSNC's curtailments during January 2014 were much more frequent and extensive than curtailments in prior years and that the reason for so many additional curtailments was the projected high demands by firm customers during several prolonged periods of extremely cold weather. He further testified that during the month PSNC's system achieved its all-time highest monthly throughput, which was approximately 1.1 million dts higher than its previous record; the system set a record daily throughput on January 7, which was more than 43,000 dts higher than the previous record; and that the system also exceeded the daily throughput record on January 24 and 29. Of the five highest individual days of throughput recorded on PSNC's system, January 2014 had four of those days, during which all or a substantial amount of PSNC's interruptible load was curtailed.

Witness Ratchford further testified that if a customer makes arrangements with PSNC in advance, PSNC may in its discretion provide the customer with gas on an emergency basis during the curtailment (Emergency Service). A customer receiving energy service in this situation pays a lower penalty amount than those customers that do not make the prior arrangements with PSNC. Under the tariff, curtailed customers that did not make arrangements for Emergency Service are deemed to have taken Unauthorized Gas. Although the penalty amounts differ, the cost of gas for Emergency Service and Unauthorized Gas is calculated the same way under Rider A of PSNC's tariff.

PSNC witness Jackson testified that during January 2014, a total of 92 interruptible customer accounts were billed for either On-Peak Emergency Service (12,702 dts), Limited Emergency Service (3,632 dts), or Unauthorized Gas (60,574 dts).

PSNC witness Ratchford testified that when a customer refuses to curtail its usage as directed, whether it burns gas pursuant to arrangements for Emergency Service or as Unauthorized Gas, it is required to pay for the gas used in accordance with the formula found in paragraph 5 of Rider A. In its February 19, 2014 filing, due to the unprecedented high gas prices, the Company proposed to modify the cost of gas calculation for January 2014 by using the highest cost flowing gas for the month, plus applicable transportation charges, fuel retention, and surcharges. Witness Jackson testified that extraordinary cold weather experienced in January of 2014 resulted in a "blowout of natural gas prices." She stated that even after what may have been the worst natural disaster the industry has seen, Hurricanes Katrina and Rita, the highest price PSNC paid was in the $25/dt range. PSNC witness Jackson testified that the formula reflects the highest cost that could be incurred for gas acquired to supply PSNC's system for the applicable month or procured as daily supply on the spot market and delivered to the PSNC system. Exhibit 1 to her testimony shows the applicable monthly and daily index prices for the days of curtailment and the higher of those two prices, which would be the amount charged for gas under Rider A. This exhibit shows that during January 2014 the cost of gas as calculated under Rider A ranged from a low of $4.97695/dt on January 10, 11, and 15, when the monthly index price was higher than the daily prices, to a high of $136.00/dt on January 22.

The Public Staff witnesses testified that based on the Public Staff's understanding of the history of Rider A, the Public Staff views the charges under Rider A as consisting of a penalty component and a cost of gas component. The first part of the Rider A calculation deals with the penalty component, which is the fixed amount charged for the specific type of Emergency Service taken. Paragraph 8 of Rider A authorizes PSNC to provide Emergency Service to curtailed customers. Curtailed customers that use gas otherwise are deemed to have burned Unauthorized Gas. The fixed charges for Emergency Services under Rider A are as follows: 1) customers provided Emergency Service are charged $1.00 per therm ($10.00/dt) plus the cost of the gas consumed, or, 2) if PSNC was utilizing a peak-shaving capability (on-system liquefied natural gas) that day, $1.50 per therm ($15.00/dt), plus the cost of the gas consumed. Emergency Service provided on a day when peak shaving was utilized is called On-Peak Emergency Service and otherwise is called Limited Emergency Service. The fixed charge for customers taking Unauthorized Gas is $2.50 per therm ($25.00/dt), plus the cost of gas. During the January 2014 curtailments, some of the curtailed customers were provided Limited or On-Peak Emergency Service and others took Unauthorized Gas.

The Public Staff witnesses testified that the second part of the Rider A calculation deals with the cost of gas component. They also testified that they believed that the incremental rates per therm for Emergency Service and Unauthorized Gas in the calculation in Rider A for the cost of gas were meant to be a fair proxy for the price that would have been required and incurred to serve those customers during the times of curtailment. The cost of gas for both Emergency Service and Unauthorized Gas is calculated under Paragraph 5 of Rider A by using the higher of: (a) the monthly contract index price for the applicable month as published in Inside F.E.R.C.'s Gas Market Report, "Prices of Spot Gas Delivered to Pipelines," "Transcontinental Gas Pipe Line Corp. (Transco) - Zone 3 (pooling points)," "Index," plus the 100% load factor rate under Transco's currently effective Rate Schedule FT for deliveries from Zone 3 to Zone 5, including applicable fuel retention and surcharges, or (b) the absolute high price for the day of consumption as published in Gas Daily in the "Daily price survey," "Citygates," "Transco, Zone 5 delivered," "Absolute," high end of the range. According to the Public Staff witnesses this formula, which was intended to be a proxy for the cost of gas to serve customers under Rider A, never anticipated such large differentials as occurred this winter.

The Public Staff witnesses confirmed that applying the Rider A cost of gas calculation would result in gas prices as high as $136.00/dt. As explained by PSNC witness Ratchford, the wide range in prices was due to extreme spikes in the daily price of delivered gas during the month. The Public Staff witnesses further testified that the reason for the extreme price spikes in January 2014 was due to capacity constraints in Transco Zone 5. The Public Staff also testified that previously the capacity constraints were only in Zone 6 and has now moved its way down to Zone 5. They additionally explained that if one goes further south on Transco's system, the other zones were not necessarily constrained, and the price did not react in the same manner and was not as volatile as in Zone 5.

Witness Ratchford also testified that the affected customers may experience an undue hardship. He further testified that, in addition to PSNC receiving letters from customers, he had spoken face-to-face with several affected customers that expressed concerns over potential hardships of paying such exorbitant prices. The Public Staff witnesses agreed that applying the Rider A cost of gas would be extremely burdensome and, in some cases, devastating to affected interruptible customers. They strongly maintained that these customers should not be penalized with an exorbitantly high cost of gas that PSNC did not actually incur. Witness Ratchford testified that PSNC did not purchase any delivered gas at the high prices reflected in the Rider A cost of gas calculation. He further testified that any curtailed customer that continued to take gas did so using PSNC's system supply.

The Public Staff stated that it had recalculated the amount of the highest flowing system gas supply cost using a weighted average of the highest cost flowing gas for the volumes billed under Rider A and, based on that recalculation, recommended a cost of gas of $6.0680/dt. In her rebuttal testimony, PSNC witness Paton agreed with the Public Staff's proposal for the limited purposes of this proceeding only.

While mindful of the financial hardship experienced by some customers if the approved PSNC tariffs are enforced during January 2014, the Commission is constrained to conclude that charging $6.0680/dt when the tariff specifies charging the higher of the monthly index for zone 3 transportation or the daily index for zone 5 delivered is inadvisable if not impermissible. The proposed $6.0680/dt cost of gas would be a departure from PSNC's tariff rather than merely a modification. The Commission concludes that it is constrained in its duties to comply with Chapter 62 so that irrespective of the extremely low and prolonged temperatures in January 2014, as well as the extraordinary increases in the daily indices, an after-the-fact departure from the Rider A indices approved by the Commission and in effect at the time in January 2014 the curtailed and interruptible customers consumed natural gas service is unwise if not altogether impermissible.

The terms of Rider A are not ambiguous. Whatever the intent that may have resulted in basing charges on the indices chosen rather than other proxies or the cost of flowing gas, the Commission determines that it should not retrospectively assess whether intent was properly manifested in the tariff terms when during January 2014 such terms (1) were in full force and effect, (2) were deemed by law to be just and reasonable, and (3) were deemed to have been known to and understood by customers subscribing to the schedule when the service was provided.

The facts of this case are somewhat unique in that PSNC filed its requests after service to interruptible customers was provided under Rider A but before PSNC billed them. The more prototypical case raising the issue of adjusting rates retroactively is where the issue is service both provided and paid for in past periods. Likewise, the equities that might justify relief in this case are particularly compelling. Still, the doctrine against retroactive rate adjustments (State ex rel. Utilities Comm'n v. City of Durham, 282 N.C. 308, 318, 193 S.E.2d 95 (1972); State ex rel. Utilities Comm'n v. Morgan, 277 N.C. 255, 267, 177 S.E.2d 405 (1970)) and similar retrospective adjustments (State ex rel. Utilities Comm'n v. Edmisten, 291 N.C. 451, 468-69, 232 S.E.2d 184, 194-95 (1977) circumscribe the Commission's authority to grant the relief requested here. This is not a case where the financial shortfall from the dispensation PSNC seeks for some of its ratepayers is borne by the Company's shareholders. Likewise, there is no bill in dispute resulting in a contested issue over whether service provided is adequate or properly measured under the tariff. The Commission likewise finds the facts of this case distinguishable from the 1991 Dominion docket, E-22, Sub 327, cited by PSNC at the agenda conference.

The Public Staff witnesses testified that in the Commission's March 6, 2014 Order the Commission allowed PSNC on a provisional basis to modify its bills for the cost of gas consumed by PSNC's customers that received Emergency Gas Service or Unauthorized Gas under PSNC's Rider A during the month of January 2014. The results of these billings are reflected in PSNC's February 2014 and March 2014 deferred accounts. PSNC credited its Sales Only Customers deferred account for $486,105.65 for the cost of gas supply used for Emergency Gas priced at the highest flowing gas supply cost of $6.3397 for the month of January 2014.

PSNC also credited the Emergency Gas surcharges of $1,741,200 billed to its customers in its All Customers' deferred account.

The Public Staff witnesses testified that if the Commission requires PSNC to bill the cost of gas as determined by the existing formula in Rider A, the Sales Customers Only deferred account balance would reflect an additional credit of $3,841,486.81 due to the higher level of collections from interruptible customers. Public Staff witness Davis testified that "everything we do that pertains to R1-17(k) and 133.4, G.S. 62-133.4 is about cost of gas incurred and true-up and that the Company makes no margin on." He asserted that since the $3.8 million was not actually incurred, the amount should not be credited to the Sales Only Deferred Account. In support of that argument, the Public Staff witnesses quotes testimony from PSNC witness Paton in Docket No. G-5, Sub 495:

> We are proposing to add a provision to Rider A, Curtailment of Service Under Commission Rule R6- 19.2 that sets forth the formula to be used to determine the price of any Emergency or Unauthorized gas sold pursuant to this Rider. This will ensure that a customer receiving gas under this rider pays any additional cost incurred by the Company to provide the gas.

Public Staff witness Davis stated that the gas cost component of Rider A was meant to simply cover the cost of gas incurred and the proposed modification to PSNC's Rider A arises from an attempt to comply with the intent of the tariff rather than with what the tariff actually requires. For that reason, failure to credit the Sales Only Deferred Account produces no inequitable result.

The Public Staff witnesses testified that there is no cross-subsidization of curtailed customers by other ratepayers. The surcharges for emergency and unauthorized gas received by PSNC are credited to its All Customers deferred account, which ensures that PSNC does not profit from its curtailment of interruptible customers. By crediting the highest flowing gas supply costs incurred by PSNC and billed to customers to the Sales Only Deferred Account, all of the other ratepayers receive 100% of the benefit.

Based on the testimony and other information in the record, the Commission concludes that PSNC appropriately billed its customers the penalty component for Emergency Gas and Unauthorized Gas. The Commission also notes that PSNC requested permission from the Commission for a limited modification of its Rider A for January 2014 and that PSNC billed its customers the January 2014 higher cost of gas under Rider A, as ordered by the Commission in its March 6, 2014 Order.

Nevertheless, pursuant to G.S. 62-130, the Commission is required to approve just and reasonable rates. Once approved in a general rate case, the rates became charges presumed to be just and reasonable, irrespective of what the Commission's intent may have been at the time the rates were approved. G.S. 62-132. In PSNC's last general rate case, the Commission concluded that Rider A established just and reasonable rates for interruptible customers that choose not to curtail and decide, instead, to use Emergency Service or Unauthorized Gas. The Commission deems it unwise to establish a precedent even in the circumstances presented in this case to modify, for service received in the past, tariffs on the theory that the terms of the tariff fail to comply with representations of the intent purportedly behind unambiguous tariff terms.

General Statute 62-139 provides, in pertinent part:

> No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission, nor shall any person receive or accept any service from a public utility for a compensation greater or less than that prescribed by the Commission.

In the present docket the curtailable and interruptible customers received gas service under Rider A before any modification was requested or addressed. After the service was provided PSNC has requested that the Commission modify Rider A to significantly reduce the cost of gas component charged to interruptible customers in January 2014. PSNC's motivation and its purpose are commendable. PSNC is attempting to avoid what it perceives to be unfair rate impacts on interruptible customers resulting from the extremely cold weather and unusually high spot market gas prices in January 2014.

While, for arguments sake, it may be assumed that during January 2014 the tariffs did not produce charges as anticipated or foreseen, they produced charges according to terms as written and approved. To the extent modifications are justified so that the tariff terms comply with the intent testified to by witnesses in this docket, the Commission concludes that such modifications must be made to affect prospective, not past, gas service.

The Commission has given considerable thought to its obligation to approve just and reasonable rates and to require PSNC to collect those rates according to the terms of PSNC's tariffs. With regard to PSNC's interruptible rates, one feature of the cost of gas component of Rider A allows PSNC to fully recover its cost of gas in providing Emergency Service and Unauthorized Gas to Rider A customers that choose not to curtail their usage when notified to do so by PSNC. Another equally important feature of the cost of gas component is that it provides an incentive for interruptible customers to curtail their usage when they are notified to do so. After all, that is the single justification for having interruptible rates. Although Emergency Service is appropriate in some circumstances, it should be the exception rather than the rule. Further, the taking of Unauthorized Gas should be strongly discouraged.

Volatility in the monthly and daily index prices of natural gas has been a common place occurrence and certainly such was the case when the Commission approved Rider A based on the monthly and daily indices. Indeed, the Commission views the probability of price volatility at some point as an inducement for those weighing the advisability of subscribing to interruptible schedules and determining whether to comply with curtailment notices. If an interruptible customer studies, understands and weighs the risk of high gas prices to be paid under the monthly and daily indices, then decides to use Emergency Service or take Unauthorized Gas, that customer has made a knowing and conscious decision to risk the payment of high gas prices rather than to curtail its usage. When that risk materializes into a need to acquire energy service or unauthorized gas, the

Commission expects the customer to bear the consequences of its decision and pay the cost of gas according to the tariff.

The Commission is concerned that should it authorize after-the-fact modifications to tariffs in effect when service has been provided in this difficult circumstance, it will set a precedent of questionable legality and one that should be avoided as poor practice.

While the parties make a forceful case that equitable relief is justified in these unique circumstances, granting the relief requested has countervailing and adverse consequences to PSNC customers other than those who chose not to curtail when notified that they should do so. The evidence in this docket demonstrates that interruptible customers enjoy substantially lower rates than firm customers. The consideration for those lower rates is the fact that PSNC can plan and operate its system at a lower capacity, and thus at a lower cost, because it can depend on curtailing its interruptible customers when weather and other events place a strain on the system. However, if interruptible customers are permitted to ignore curtailment notices and to continue to use gas as if no curtailment has been called by PSNC, interruptible customers are charged more like firm customers than interruptible ones, without paying the substantially higher rates that firm customers pay. Further, PSNC will lose confidence that it can plan its system based on having the ability to curtail interruptible customers.

Moreover, because interruptible customers pay substantially lower rates than firm customers, the Commission is concerned that PSNC's proposed modification of Rider A may result in firm customers subsidizing interruptible customers. Revenue received by PSNC under the cost of gas component of Rider A is credited to PSNC's Sales Customers Only deferred account. According to PSNC's testimony, customers on the Sales Customers Only schedules include all residential customers. The Rider A modification requested by PSNC and supported by the Public Staff would result in PSNC receiving $3.8 million less from interruptible customers for Emergency Service and Unauthorized Gas in January 2014 than PSNC will receive if the tariff is enforced as written. As a result, PSNC's Sales Customers Only deferred account would have a balance that is $3.8 million less than if Rider A is enforced as written.

The Public Staff witnesses referred to this $3.8 million as a “windfall” or a “benefit” that will be received by PSNC's firm customers. The Commission is unpersuaded that these characterizations correctly capture the appropriate relationship between the customer classes. The testimony of PSNC's witnesses shows that for at least ten years PSNC's interruptible customers have enjoyed the advantage of paying substantially lower rates than PSNC's firm customers, yet have rarely, if ever, been required to curtail their gas service. In January 2014, when they were notified to curtail, some interruptible customers made a business decision to continue using gas and to pay the tariffed rate for Emergency Service and Unauthorized Gas under Rider A. That will result in PSNC's firm customers receiving some financial offset according to approved tariffs to the higher firm rates they have agreed to pay. Also, it will result in PSNC's interruptible customers paying the tariffed rates that they agreed to pay when they chose not to curtail their gas usage in January 2014. Further, it will result in PSNC receiving the proper amount of revenue to be credited to its Sales Customers Only deferred account. Moreover, other customers on Rider A curtailed usage when instructed and accepted the adverse consequences inherent in their earlier decision to subscribe to Rider A and their decision in January 2014 to curtail as instructed. While PSNC escaped purchasing exorbitantly high-priced gas on the spot market in January 2014, the situation would have been different if all the Rider A customers had refused to curtail.

As stated above, the Commission is mindful of the difficulties to which affected interruptible customers are placed by enforcing PSNC’s tariffs as written. Consequently, the Commission finds good cause to provide PSNC's interruptible customers with a measure of relief by giving them additional time to pay their January 2014 bills. In the Commission's March 6, 2014 Order Allowing Modified Billing of Rider A Customers Pending Hearing on Petition, the Commission directed PSNC to bill the full amount owed under the terms of Rider A for January 2014, but to allow customers to pay, on an interim basis and without late fees or interest, PSNC's proposed modified Rider A amount. The Commission concludes that it is appropriate to grant PSNC's interruptible customers a further extension of time in which to pay the balance owed under Rider A for January 2014. Accordingly, the Commission will direct that PSNC allow these customers to pay the balance owed under Rider A for January 2014 in equal installments over the next 18 months, beginning on October 1, 2014, without the imposition of late fees or interest so long as the customer makes each installment payment on time. In addition, the Commission will allow PSNC to negotiate an installment payment arrangement of more than 18 months with any customer that is in a situation that PSNC deems appropriate for a longer payment plan. However, in those situations the risk of failing to collect the full amount owed by any such customer shall rest with PSNC. That is, if a customer is given more than 18 months and fails to pay any portion due to PSNC, then PSNC shall not be allowed to recover that unpaid balance from PSNC's ratepayers as an uncollectible expense or as any other cost of service item. By placing this responsibility upon PSNC the Commission expects the Company to monitor with vigilance the credit worthiness of customers to whom additional extensions are allowed and to impose such reporting requirements as are necessary in exchange for the extensions.

The Commission is concerned that there are some PSNC customers receiving service under interruptible tariffs that are not well positioned to in fact curtail their gas usage when notified to do so by PSNC. In particular, the Commission is concerned that PSNC should review the requirements of interruptible tariffs to make certain that public service entities, such as hospitals, colleges and prisons, understand their obligation to curtail and understand the cost they will incur under Rider A if they fail to curtail. Therefore, the Commission concludes that there is good cause to require that PSNC engage in a person-to-person (by telephone or in-person) discussion with the appropriate manager or decision maker of each public service entity presently being served under an interruptible tariff. PSNC should fully explain the curtailment obligation of such customers, the consequences of choosing to not curtail, the cost of gas under the Rider A indices, and give each customer a copy of this Order. Further, PSNC shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its person-to-person discussion with the appropriate manager or decision maker of each public service entity and stating whether that customer has decided to continue receiving service under an interruptible tariff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence for this finding of fact is contained in Ratchford Exhibit 4.

Commission Rule R6-12(2) requires LDCs to, “Assist the customer or prospective customer in selecting the most economical rate schedule.”

PSNC’s cheapest sales rates are its Rate Schedule 150: “Large-Quantity Interruptible Commercial and Industrial Service” and the corresponding transportation tariff, Rate Schedule 180. To qualify for Rate 150 and 180, a customer must use in excess of 50 dekatherms per day on an annual basis. Per Rule R6-12(7), each summer PSNC is required to review the consumption for each qualifying customer for the twelve months ending June 30 of the past two years. If a customer has not been using 50 dts/day, it is automatically reclassified to a more expensive rate schedule.

The tariff for Rate Schedule 150 explicitly states, “All Gas purchased under this Rate Schedule shall be separately measured from any Gas purchased or transported under any other Rate Schedule. Separate Meters, separate Accounts, and separate locations may not be combined in determining quantities for billing.” So if a customer seeking service under Rate 150 wants gas on a firm basis for some need (such as space heating), (1) it must purchase that gas under a more expensive rate schedule and, (2) it may not count volumes consumed under the more expensive rate schedule towards its 50 dts/day requirement to qualify for Rate 150.

According to Ratchford Exhibit 4, several customers failed to curtail because they wanted to continue to use natural gas for such uses as pre-heating, heating, or other equipment. For those volumes needed for such uses, the Commission is of the opinion that these customers should have been on a firm rate. Also, the Commission concludes that such volumes should not have gone toward their 50 dts/day total. The Commission is concerned that PSNC may not have properly assisted these customers in selecting their rate schedules. “Most economical” means within the meaning of the tariffs. PSNC should seek Commission approval to grant variances to its tariffs.

Based on this evidence, the Commission is concerned that there may be PSNC interruptible customers receiving natural gas on a firm basis for space heating and other uses that should be provided under a firm service rate. Therefore, the Commission concludes that there is good cause to require that PSNC engage in a comprehensive review of the Emergency Service and Unauthorized Gas used during January 2014, as well as PSNC's previous customer consumption records, and determine whether there are interruptible customers receiving natural gas for space heating and other uses that should be provided under a firm service tariff. Further, PSNC shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its investigation of this matter and stating all actions that PSNC has taken to ensure that all interruptible customers receiving gas for space heating and other uses that should be provided under a firm service rate have been required to obtain a separate meter for that firm service under an appropriate firm service tariff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence for this finding of fact is contained in the joint testimony of the Public Staff witnesses and the rebuttal testimony of PSNC witness Paton.

In their joint testimony the Public Staff witnesses recommended a modification to the Rider A cost of gas calculation going forward. PSNC witness Paton testified in rebuttal that it was premature for the Commission to consider the recommendation at this time, and that any changes to PSNC's tariff should be considered after the Company files its proposal as required by the Commission's Order of March 6, 2014.

In its June 4, 2014 filing, PSNC proposed to make several changes to Rider A. PSNC's first proposed change is to simplify the calculation of gas costs under paragraph 5 of its Rider A for Emergency Services and Unauthorized Gas. PSNC proposes to change this calculation to two times the current benchmark cost of gas as determined under its Rider D. PSNC stated that this change will be simple and transparent. PSNC's second proposed change is to eliminate its On-Peak Emergency Service and instead have only one type of Emergency Service with a surcharge assessment of $2.00 per therm.

In its filing, PSNC also proposed to require that an interruptible customer must have an installed and operable alternate fuel capability to be eligible to request Emergency Service during a curtailment event. PSNC's final proposed change is a modification of the assessment rates, or surcharges. PSNC proposes to increase the Unauthorized Gas assessment to $5.00 per therm (currently it is $2.50 per therm).

The fundamental premise of PSNC's petition is that the extraordinary conditions of the 2014 Polar Vortex make the application of Rider A unfair. While there may be merit in the suggestion that modification to Rider A may be justified based on the January 2014 experience, the Commission determines that a more comprehensive analysis than that contained in the record in this docket should be undertaken before making a permanent change. In addition, Rider A was adopted in PSNC's general rate case. The Commission weighed all the evidence and considerations affecting firm and interruptible service, then decided that PSNC's interruptible tariffs struck the appropriate balance for approving substantially lower rates for interruptible customers, providing an incentive to interruptible customers to curtail, and requiring them to pay a premium if they do not curtail. That balance should not be altered in the present docket where the Commission does not have before it adequate evidence to support a need for such changes.

Based on the facts in the record, the Commission concludes that any changes to PSNC's tariffs should be considered in a docket that provides the Commission with full information and allows the Commission adequate time to review the effects of proposed changes on all of PSNC's ratepayers, not just its interruptible customers. Accordingly, the Commission will defer its consideration of any changes to PSNC's tariffs until PSNC files a request for changes in a separate docket or in a general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's request to charge its interruptible customers a modified cost of gas component for the cost of Emergency Service and Unauthorized Gas billed under Rider A during January 2014 is denied. However, customers shall be allowed to pay the additional amount owed in equal installments during the 18 month period beginning on October 1, 2014 and ending on March 31, 2016, without the imposition of a late fee or interest charge, so long as all installment

payments are made on time. In addition, PSNC shall be allowed to negotiate an installment payment arrangement of more than 18 months with any customer that is in a situation that PSNC deems appropriate for a longer payment plan. Further, PSNC may include the payment of interest in a negotiated payment plan beyond the initial 18 month period, if deemed appropriate by PSNC. However, in those situations the risk of failing to collect the full amount owed by any such customer shall be on PSNC. Thus, if a customer is given more than 18 months and fails to pay any portion due to PSNC, then PSNC shall not be allowed to recover that unpaid balance from PSNC's ratepayers as an uncollectible expense or as any other cost of service item.

2. That PSNC's request in this docket to make permanent modifications to Rider A for future service is denied, without prejudice for PSNC to file its request in a separate docket or in a general rate case.

3. That PSNC shall engage in a person-to-person discussion with the appropriate manager or decision maker of each public service entity presently being served under an interruptible tariff. PSNC shall fully explain the curtailment obligation of such customers, the consequences of choosing to not curtail, the cost of gas under the Rider A indices, and give each customer a copy of this Order. Further, PSNC shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its person-to-person discussion with the appropriate manager or decision maker of each public service entity and stating whether that customer has decided to continue receiving service under an interruptible tariff.

4. That PSNC shall conduct an investigation to determine whether there are interruptible customers receiving natural gas on a firm basis for space heating and other uses that should be provided under a firm service tariff. PSNC shall file a report with the Commission no later than 60 days after the issuance of this Order providing the details of its investigation of this matter and stating all actions that PSNC has taken to insure that all interruptible customers receiving gas for space heating and other uses that should be provided under a firm service rate have been required to obtain a separate meter for that firm service under an appropriate firm service tariff.

ISSUED BY ORDER OF THE COMMISSION
This the 8th day of September, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner Don M. Bailey did not participate in this decision.

DOCKET NO. P-10, SUB 877

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Kevin Eisenhour, 4681 Fowler Road, Granite Falls, North Carolina 28630, Complainant v. Central Telephone Company, d/b/a CenturyLink, Respondent	))))))))	ORDER GRANTING CENTURYLINK'S MOTION TO DISMISS COMPLAINT FOR LACK OF JURISDICTION

BY THE COMMISSION: On February 4, 2014, Kevin Eisenhour (Mr. Eisenhour or Complainant), filed a complaint with this Commission against Carolina Telephone and Telegraph Company, LLC, d/b/a CenturyLink (CenturyLink or Company).

On February 19, 2014, CenturyLink filed its Answer and Motion to Dismiss with the Commission on February 19, 2014.

<u>FACTS AND ANALYSIS</u>

In his complaint, Mr. Eisenhour, alleges that he has been a longstanding customer of CenturyLink and that he subscribed to voice and internet services. According to the Complaint, CenturyLink provided Complainant with substandard service. Specifically, Mr. Eisenhour alleged that CenturyLink failed to satisfactorily resolve his complaint about the wire that ran from his Network Interface Device (NID) into his home, i.e., his inside wiring, and that CenturyLink provided him with defective modems and ports. According to Mr. Eisenhour, the failure of CenturyLink to resolve these complaints either rendered his telephone and/or internet services unusable and/or substantially impaired his ability to use those services. As a result, Complainant refused to pay for these services and CenturyLink disconnected his service on January, 2014. By this Complaint, Mr. Eisenhour seeks an order from this Commission directing CenturyLink to restore his telephone and internet services (which includes replacement of the wire leading from the Network Interface Device (NID) to the inside connection) and to abolish the outstanding $325.56 charges that have been applied to his account, the non-payment of which has caused his services to be disconnected.

In its Answer, CenturyLink responded to each of the material allegations in the Complaint and moved that Mr. Eisenhour's complaint be dismissed because the Commission lacks jurisdiction over the subject matter of the Complaint. Specifically, CenturyLink alleges that this Commission has no authority to adjudicate Mr. Eisenhour's claim because CenturyLink elected to have its rates, terms and conditions for its services determined pursuant to G.S. 62-133.5(h) and because Mr. Eisenhour is complaining about the Company's failure to properly repair wiring running from his NID to his customer premises equipment (CPE). For the reasons stated below, we conclude that the Commission lacks jurisdiction over the subject matter of the complaint and, therefore, we must dismiss Mr. Eisenhour's complaint.

At the outset, the Commission notes that we have previously discussed the limits of our jurisdiction with regard to G.S. 62-133.5 (h). In the Matter of Implementation of Subsection (h) Price Plans Pursuant to House Bill 1180, N.C.U.C. Docket No. P-100, Sub 165 (October 20, 2009), we acknowledged that the amendment to G.S. 62-133.5 creates a new category of price plan. Any local exchange carrier or competing local provider may opt into this new category of price plan by filing notice of its intent to do so with the Commission. We describe these price plans as "Subsection (h) price plans." In reviewing these types of plans, we acknowledge that they provide extensive deregulation of an eligible company's "terms, conditions, rates, or availability relating to its retail services." However, we have also previously stated that "while the deregulation is very extensive by historical standards, it is not a complete deregulation." In noting this status, we highlight the circumstances in subsection (6) in which our jurisdiction is not impacted despite a local exchange company's election under the statute. The subsection specifically enumerates seven (7) situations in which jurisdiction are not impacted; none of the circumstances are pertinent in the case at hand. With these principles in mind, we examine the remainder of G.S. 62-133.5(h) to determine if we have jurisdiction to resolve Mr. Eisenhour's complaint.

In pertinent part, G.S. 62-133.5(h) states:

(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 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 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 tariffed as of the date of the election; or impose any constraints on the rates of the local exchange company's services that were subject to full pricing flexibility as of the date of election.

Briefly summarized, the pertinent portion of this statute provides that a telephone company such as CenturyLink will be subject to reduced Commission regulation if it elects to be regulated under G. S. 62-133.5(h) and (1) it holds itself open to competition in its territory; (2) it continues to offer stand-alone basic residential lines to all customers who choose to subscribe to that service; (3) 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; and (4) it commits to not raising rates annually for stand-alone basic residential rates in excess of the percentage increase over the prior year in the Gross Domestic Product Price Index unless authorized to do so by the Commission. On March 8, 2012, CenturyLink notified the Commission that it was electing to be regulated pursuant to G.S. 62-133.5(h). The election became effective on April 1, 2012.

In the notification, CenturyLink certified that (1) its territory was open to competition; (2) it would continue to offer stand-alone basic residential service to all customers chose to subscribe to it; (3) it committed 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 as evidenced by the schedules attached to the notification; and (4) it would not raise rates for stand-alone basic residential rates in excess of the percentage increase over the prior year in the Gross Domestic Product Price Index. With this notification, CenturyLink satisfied the statutory requirements to be regulated pursuant to G.S. 62-133.5(h). Thus, from April 1, 2012 forward, the Commission's regulation of CenturyLink must be informed by the terms of the statute and the choices made by the customer.

According to CenturyLink's certification, it offers a stand-alone basic residential telephone line at rates that are less than or comparable to rates charged to urban customers for the same line for any customer who chose to subscribe to that service. Stand-alone basic residential line service is defined as: "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." Mr. Eisenhour chose not to subscribe to a stand-alone residential line. Instead, he chose to receive phone and internet services from CenturyLink, i.e., Single Choice Bundle which includes unlimited long distance and 10M Internet connect. By exercising that option, Mr. Eisenhour chose a service other than basic stand-alone residential service which was billed on a recurring basis on his bill. In that circumstance, the statute provides that the Commission may not impose any requirements related to the terms, conditions, rates, or availability of any of the local exchange company's retail services or otherwise regulate any of the local exchange company's retail services except its stand-alone basic residential line service once a subsection election is made. G.S. 62-133(h)(2) and (3). Stated more succinctly, the Commission may not exercise regulatory authority over complaints concerning CenturyLink's failure to provide suitable service in that situation. To the extent that the customer has a complaint in that regard, such complaint must be pursued in another forum.

Mr. Eisenhour also complains that CenturyLink has failed to properly repair his wiring that runs from his NID to his CPE. Again, CenturyLink moves this Commission to dismiss the Complaint for lack of subject matter jurisdiction. Effective January 1, 1987, the Federal Communications Commission deregulated installation and maintenance of inside wiring, Second Report and Order, Detariffing the Installation and Maintenance of Inside Wiring, 1986 WL 92429. This Commission followed suit in Docket P-100, Sub 90. From that date forward, the Commission has not exercised regulatory authority over inside wiring. Therefore, this Complaint, to the extent that it requests Commission assistance in resolving the dispute between CenturyLink and Mr. Eisenhour regarding the Company's faulty repair of his inside wiring, must also be dismissed.

CONCLUSION

After a careful review of the filings to date in this docket, the Commission concludes that good cause exists to grant CenturyLink's Motion to Dismiss the Complaint for Lack of Jurisdiction for the reasons set forth above and to close this docket.

IT IS, THEREFORE, ORDERED that the complaint is hereby dismissed and this Order shall be served on Complainant by United States certified mail, return receipt requested and on Respondent by electronic mail (e-mail), delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of July, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Chairman Edward S. Finley, Jr., did not participate in the decision of this Order.

DOCKET NO. P-118, SUB 192
DOCKET NO. P-16, SUB 257
DOCKET NO. P-31, SUB 159
DOCKET NO. P-1394, SUB 4
DOCKET NO. P-1136, SUB 5
DOCKET NO. P-748, SUB 7
DOCKET NO. P-738, SUB 7
DOCKET NO. P-303, SUB 8
DOCKET NO. P-561, SUB 30
DOCKET NO. P-785, SUB 4
DOCKET NO. P-1286, SUB 2
DOCKET NO. P-1455, SUB 2
DOCKET NO. P-1348, SUB 2
DOCKET NO. P-1341, SUB 7
DOCKET NO. P-617, SUB 6
DOCKET NO. P-520, SUB 1
DOCKET NO. P-1570, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application for Declaratory Ruling that No Approval is Necessary With Respect to Transfer of Certain Assets of Windstream North Carolina, LLC, Windstream Concord Telephone, Inc., and Windstream Lexcom Communications, Inc., and the Windstream Competing Local Providers, or Alternatively, Approval of Said Transfer	)))))))	DECLARATORY RULING

BY THE COMMISSION: On August 5, 2014, Windstream Holdings, Inc. (Windstream), Windstream North Carolina, LLC (ILEC)[1], Windstream Concord Telephone, Inc. (ILEC), Windstream Lexcom Communications, LLC (ILEC)(all collectively known as the ILECs); Windstream Communications, Inc. (CLP/LD)[2], Intellifiber Networks, Inc. (CLP/LD)[3], Network Telephone Corporation (CLP/LD), The Other Phone Company, Inc. (CLP/LD), Talk America, Inc. (CLP/LD), US LEC of North Carolina, LLC (CLP/LD), PaeTec Communications, Inc. (CLP/LD), Windstream Norlight, Inc. (CLP/LD), Windstream NTI, Inc. (CLP/LD), Windstream KDL, Inc.

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[1] Incumbent Local Exchange Company (ILEC).

[2] This entity and certain other Applicants have been certificated by the Commission as Competing Local Providers (CLPs) and/or as providers of interexchange/long distance (LD) service, and each such provider is designated as a CLP/LD entity.

[3] Two affiliates of this and certain other Windstream CLP Entities, McLeodUSA Telecommunications Services, LLC (McLeod USA) and LDMI Telecommunications, Inc. (LDMI), are interexchange carriers and not CLPs. Specifically, McLeod USA is a switchless reseller of interexchange telecommunications services, pursuant to a Certificate of Public Convenience and Necessity (CPCN) granted in Docket No. P-617, Sub 0. LDMI is an interexchange carrier holding a CPCN granted in Docket No. P-520, Sub 0.

(CLP/LD), and Windstream NuVox Communications, Inc. (CLP/LD), (the CLPs/LDs collectively known as the CLP/LD Companies)(the ILECs and CLP/LD Companies collectively, the WIN Companies); Communications Sales & Leasing, Inc. (CSL), and Talk America Services, LLC (TAI) (Windstream, the ILECs, the CLP/LD Companies, CSL and TAI, collectively, the Applicants) filed an Application to request that the Commission issue a declaratory ruling that Commission approval of the transfer of certain WIN ILEC and CLP assets to CSL is not necessary under the North Carolina Public Utilities Act; or, in the alternative, that, as described in the Application, the Commission approve the transfer of the assets as described therein.

In support of the request, the Applicants asserted that:

1. Windstream is the parent company to the ILECs and CLP/LD Companies. Windstream is not authorized to provide telecommunications services in North Carolina and is not seeking to become a regulated telecommunications carrier or public utility.

2. The ILECs are certificated in North Carolina to provide local exchange services and are wholly owned subsidiaries of Windstream.

3. The CLP/LD Companies are wholly owned indirect subsidiaries of Windstream. The CLP/LD Companies are certificated as competing local providers and/or long distance telecommunications service providers.

4. CSL is a newly formed Delaware corporation and will elect to operate as a Real Estate Investment Trust (REIT). CSL will not provide service on a retail or wholesale basis or operate as a telecommunications carrier.

5. TAI is a newly created subsidiary of CSL. As part of the transaction and upon certification by the Commission, TAI will operate as a CLP and long distance carrier in North Carolina where the CLPs/LDs are currently providing service. Upon Commission certification of TAI and following notice to the customers, the residential and local and long distance customers of the CLP/LD Companies will be transferred to TAI. TAI will become the telecommunications service provider for the CLP/LD Companies' residential customers. The CLP/LD Companies will retain all of their business customers.

6. Under the transaction proposed, certain fixed assets of the WIN Companies, including copper, fiber, real estate and other network assets will be transferred to CSL and CSL will lease those assets back to Windstream on a long-term basis for the exclusive use and benefit of the WIN Companies. The WIN Companies will be responsible for the operation and maintenance of the assets and will continue to have responsibility for quality of service standards and fulfillment of all regulatory obligations.

7. The transaction is pro forma under the Federal Communications Commission's (FCC's) rules and does not require approval by the FCC.

8. CSL is not a public utility because it will not be holding itself out as willing to serve, indiscriminately, all who have applied because of its exclusive long term lease arrangement with Windstream and because it will not be providing any service to the public for compensation.

9. CSL is not required to apply for and receive a CPCN from the Commission to acquire the subject assets from the WIN Companies and to lease those assets back to Windstream for the benefit of the WIN Companies because it does not fall within the definition of public utility as set forth in G.S. 62-3(23)a.6.[1]

10. Commission approval of the transfer of the subject assets is not required under the North Carolina Public Utilities Act.

On August 15, 2014, the Commission issued an Order Requesting Comments from the Public Staff, the Attorney General, ILECs, CLPs and any other party interested in the subject matter of the Applicants' request. The Commission requested that the parties address the following questions:

a. Under the circumstances described in [the Application], would CSL be a public utility as defined in G.S. 62-3(23)a.6? Explain.

b. Does the Public Utilities Act require Commission approval of a transfer of public utility assets to an entity that does not have a CPCN and/or does not intend to provide public utility service? Explain.

c. Can a public utility transfer its CPCN/authority to operate to another entity? Explain.

d. Is Commission approval of the transaction as described herein required? Explain.

e. Assuming Commission approval is required, have the Applicants satisfied the statutory criteria for approval of the transaction? Explain.

f. Are there any other issues that the Commission may need to address concerning the proposed transfer of assets?

Initial comments were due by August 29, 2014 and reply comments were due by September 10, 2014.

On August 28, 2014, the Public Staff filed a motion requesting an extension of time to file comments and reply comments. On August 29, 2014, the Commission extended the time to file

[1] In support of these assertions, Applicants cite the case of Utilities Commission v. Simpson, 295 N.C. 519, 246 S.E.2d 753(1978), as well as a number of declaratory rulings by the Commission involving self-regulated utilities commodities such as landfill gas, solar services, steam, and bulk wastewater treatments, for the proposition that the determination of public utility status depends on the particular facts and circumstances presented.

initial comments from August 29, 2014 to September 5, 2014. The Commission also extended the time for parties to file reply comments from September 10, 2014 until September 17, 2014.

On September 5, 2014, initial comments were filed by the Public Staff. Reply comments were filed by the Applicants on September 10, 2014.

THE PUBLIC STAFF'S COMMENTS

Briefly summarized, the Public Staff stated that:

1. Under the circumstances described in the [Application], would CSL be a public utility as defined in G.S. 62-3(23) a.6?

   No. Under the terms of the Master Lease, the WIN Companies will have exclusive rights to the transferred assets and will be responsible for the costs related to those assets. The WIN Companies will also be responsible for complying with all federal, state and local regulatory requirements. Subject to G.S. 62-110(f4) and (f5), the WIN ILECs will continue to serve as carriers of last resort in their service areas and to provide and charge appropriate contract and tariff rates to other carriers to fulfill their regulatory obligations to provide collocation and access to network elements. No customer accounts will be transferred to CSL and CSL will not hold itself out as offering service to the public. Also, the Public Staff observed that although CSL would hold title to the assets used to convey and transmit messages, the WIN Companies would operate and manage those assets and continue to perform all of the public utility functions associated with them pursuant to their existing CPCNs. Finally, the Public Staff stated that declaring CSL to be a public utility would serve no regulatory purpose under the circumstances previously described.

2. Does the Public Utilities Act require Commission approval of a transfer of public utility assets to an entity that does not have a CPCN and/or does not intend to provide public utility service?

   Maybe. Whether Commission approval is required depends on the nature of the asset. If the assets or assets to be transferred are a substantial or integral part of the system or facilities used to provide public utility service, Commission approval of the transfer or control would be required because of the impact of the transfer on the public utility rates and services.

3. Can a public utility transfer its CPCN/authority to operate to another entity?

   Yes, G.S. 62-111(a) provides that approval of such transfer "shall be given if justified by the public convenience and necessity."

4. Is Commission approval of the transaction as described in the Application required?

   No. The WIN ILECs have chosen to be regulated pursuant to G.S. 62-133.5(h). ILECs regulated pursuant to G.S. 62-133.5(h) are exempt from the transfer of control requirements set forth in G.S. 62-111(a). Similarly, the WIN CLP/LD companies are also exempt from the requirements of G.S. 62-111(a) by Commission Rules, i.e., Commission Rule R17-8(a) and statute, i.e. G.S. 62-2(b).

   In formulating its comments on this question, the Public Staff noted that two additional entities, Windstream Lexcom Long Distance, LLC[1], a LD company, and Windstream North Carolina, Inc., a Payphone Service Provider (PSP) which holds a special certificate granted in Docket No. SC 1806, Sub 0, pursuant to G.S. 62-110(c) and Commission Rule R13, were not listed in the Application. For the purposes of its comments, the Public Staff deemed these entities as among the Applicants. With regard to the PSP, the Public Staff observed that neither the statute nor the Commission Rules addressed the applicability of G.S. 62-111(a) to PSPs. The Public Staff nevertheless recommended that the Commission exempt PSPs from the provisions of G.S. 62-111(a) to the extent necessary for the purposes of the transaction proposed in the Application pursuant to the Commission's authority to "determine the extent to which such services shall be regulated." See G.S. 62-110(c).

5. Assuming Commission approval is required, have the Applicants satisfied the statutory criteria for approval of the transaction?

   Yes. North Carolina appellate courts have long held that "the public convenience and necessity doctrine is a relative or elastic theory rather than an absolute or absolute rule [and] the facts of each case must be separately considered." Utilities Commission v. Village of Pinehurst, 99 N.C. App. 224, 229, 393 S.E.2d 111, 115 (1990). In the Application, Applicants stated that the transaction is justified by the public convenience and necessity because it will enable the WIN companies to increase their financial flexibility and effectively compete in an industry that is subject to rapid technological advances. The Public Staff observed that these expected benefits are consistent with those recognized by the General Assembly in enacting the Consumer Choice and Investment Act of 2009 (S.L. 2009-238).

6. Are there any other issues that the Commission may need to address concerning the proposed transfer of assets?

   Yes. The CLP/LD Companies and TAI are subject to the provisions of Commission Rule R20-1 regarding the proposed changes to residential customers' local and long distance preferred telecommunications providers. These companies should be reminded that they must comply with the slamming and cramming rule set forth in this rule as well as the provisions established by the FCC. Additionally, the CLP

[1] Windstream Lexcom Long Distance, LLC was certificated as a long distance service provider in Docket No. P-323, Sub 0.

companies are subject to Commission Rule R21-2 which governs the notice requirements that CLP companies must comply with when transferring customers to TAI.

APPLICANTS' REPLY COMMENTS

The Applicants noted that the Public Staff was the only entity that filed comments and that the Public Staff did not oppose their request for a declaratory ruling that Commission approval for the proposed transaction was not required. The Applicants also noted that the Public Staff identified two additional Windstream entities, Windstream Lexcom Long Distance, LLC and Windstream North Carolina, Inc.[1], that were not included in the Application. With regard to the former, the Applicants explained that the Public Staff was indeed correct that Windstream Lexcom Long Distance, LLC was not included in the Application through an oversight and that it should be deemed admitted as recommended by the Public Staff. With regard to the latter, the Applicants explained that Windstream North Carolina, Inc. had been converted from a corporation to a limited liability company some years ago and has since been known as Windstream North Carolina, LLC. The Applicants further explained that Windstream North Carolina, LLC is one of the entities listed in the Application. Finally, the Applicants explained that the Public Staff was correct in noting that Windstream North Carolina, Inc. is a certificated PSP[2] and that it was not listed in the Application as it should have been. The Applicants also stated that they agreed with the Public Staff's recommendation that the Commission should exempt PSPs from any approval requirements under G.S. 62-111(a) to the extent necessary for the purposes of the transactions described in the Application.

Finally, the Applicants acknowledged that the CLP/LD companies and TAI are subject to the provisions of Commission Rule R20-1 and FCC slamming/cramming rules regarding the proposed changes to residential customers' local and long distance preferred telecommunications providers and Commission Rule R21-2 which governs the notice requirements that CLP companies must comply with when transferring customers to TAI. The Applicants indicated that they fully intend to comply with those rules and requirements.

ANALYSIS

Under the transaction as described in the Application, certain fixed assets of the WIN Companies, including copper, fiber, real estate and other network assets will be transferred to CSL and CSL will lease those assets back to Windstream on a long term basis for the use and benefit of the WIN Companies. According to the Applicants, CSL is not now a certificated telecommunications public utility in this State; and CSL has not sought and does not seek Commission certification as a telecommunications public utility by the filing of this Application. By this Application, the Applicants "request that the North Carolina Utilities Commission [] issue a declaratory ruling that approval of the transfer of certain WIN ILEC and CLP assets to CSL [] is

[1] Windstream North Carolina, Inc. was certificated as an ILEC in Docket No. P-118. Windstream North Carolina, Inc. was converted from a corporation to a limited liability company some years ago and has since been known as Windstream North Carolina, LLC.

[2] Windstream North Carolina, Inc. was also certificated as a PSP in Docket No. SC-1369, Sub 1.

not necessary under the North Carolina Public Utilities Act, N.C. Gen. Stat. 62-1, *et seq*[.] Application for Declaratory Ruling, p. 2.

In its Order Requesting Comments, the Commission asked parties to comment on whether the Public Utilities Act requires Commission approval of a transfer of public utility assets to an entity that does not have a certificate and/or does not intend to provide utility service. In its Comments, the Public Staff stated that whether Commission approval of such a transfer under the circumstances therein described would be necessary would depend on the nature of the asset. The Public Staff further explained that if the assets to be transferred are a substantial or integral part of the system or facilities used to provide public utility service, Commission approval of the transfer of ownership or control would be required because of the impact of the transfer on public utility rates and service. See G.S. 62-111.

The Commission generally agrees with the Public Staff's assessment of the law. We do note, however, that the Commission, by rule, and the General Assembly, by statute, have seen fit to exempt certain telecommunications public utilities from such oversight and approval. As the Public Staff observed in its comments, the WIN ILECs have chosen to be regulated pursuant to G.S. 62-133.5(h) and ILECs regulated pursuant to G.S. 62-133.5(h) are exempt from the transfer of control requirements set forth in G.S. 62-111(a). See 62-133.5(g). Similarly, the Public Staff observed that the WIN CLP/LD companies are also exempt from the requirements of G.S. 62-111(a) by Commission Rule R17-8(a) and G.S. 62-2(b), respectively. Thus, because of these exemptions, neither the WIN Companies set forth in the Application nor CSL are required to seek Commission approval for the WIN Companies to transfer the assets described herein to CSL.

Although the Applicants couched their declaratory ruling request as a request for the Commission to declare that Commission approval of the transfer of the aforementioned assets from the WIN Companies to CSL was not necessary, the real impetus behind the Applicants' request is to seek a declaratory ruling that CSL will not be a public utility if and when the transaction is consummated and the ownership of the telecommunications assets resides with CSL rather than the WIN Companies. If the Commission determines that CSL will be a "public utility" if the transaction is completed as structured, CSL will be required to apply for and receive a CPCN from the Commission and will be subject to Commission regulatory authority. See G.S. 62-110. Further, if CSL is determined to be a public utility, as the transaction is now structured, CSL would have to apply for and receive Commission approval before it could transfer public utility assets by the lease agreement to Windstream. See G.S. 62-111(a).

Thus, in their Application, the Applicants request that the Commission declare that under the facts as presented, CSL does not fit within the definition of a public utility as set forth in G.S. 62-3(23)a.6 because it would neither construct nor operate facilities leased to the WIN Companies. See Application p. 6. In making their request, however, the Applicants acknowledge that CSL would own some of the facilities used for conveying or transmitting messages or communications. G.S. 62-3(23)a.6 defines a public utility as a person, "now or hereafter owning <u>or</u> operating in this State equipment or facilities for…conveying or transmitting messages or communications by telephone or telegraph, or any other means of transmission, where such service is offered to the public for compensation."

Under the clear terms of the statute, a person is a public utility if she owns equipment or facilities for conveying or transmitting messages which is then offered to the public for compensation. Because the statute is written in the disjunctive, it matters not that CSL does not construct or operate such equipment if CSL owns such equipment and offers service to the public for compensation through the use of such equipment. Thus, the fact that the Applicants will not construct or operate the facilities would not preclude CSL from being classified as a public utility that conveys or transmits messages or communications by telephone or any other means of transmission if CSL meets the remaining public utility requirements set forth in G.S. 62-3(23)a.6 and established by judicial precedent. The Commission therefore finds no merit in the Applicants' argument in this regard.

In addition to the preceding argument, the Applicants also assert that CSL will not be a public utility because CSL will not be offering any service to the public for compensation by virtue of its exclusive lease agreement with Windstream. According to the Applicants, as the transaction is now structured, CSL's exclusive customer is Windstream and not the public writ large; the WIN Companies and not CSL will provide service to the WIN Companies' customers using equipment which the WIN Companies previously owned; and the equipment and facilities previously owned by the WIN Companies are now owned by CSL and leased by CSL to Windstream for the benefit of the WIN Companies. Because the transaction is structured in this manner, the Applicants contend that CSL does not offer service to or receive compensation from the public. According to the Applicants, CSL therefore cannot be a public utility under those facts.

In support of this argument, the Applicants note that the North Carolina Supreme Court has adopted a flexible definition of "the public" under the Public Utilities Act. In Utilities Commission v. Simpson, 295 N.C. 519, 524, 246 S.E.2d 753(1978), the Supreme Court stated:

> What is the "public" in any given case depends rather on the regulatory circumstances of that case. Some of these circumstances are (1) nature of the industry sought to be regulated; (2) type of market served by the industry; (3) the kind of competition that naturally inheres in that market; and (4) effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. The meaning of "public" must in the final analysis be such as will, in the context of the regulatory circumstances, and as already noted by the Court of Appeals, accomplish "the legislature's purpose and comports with its public policy."

As noted by the Applicants, the Commission has applied this flexible approach in the past to hold that a particular entity was not a public utility. For instance, in in Re Request for Declaratory Ruling by Natural Power, Inc. and Raleigh Landfill Gas Corp., Docket No. SP-100, Sub 1, Order for Request on Ruling (December 22, 1988), this Commission issued a declaratory ruling that the use of landfill gas to produce steam for sale to a single manufacturer under a "bargained for" transaction did not bring the entities selling landfill gas or selling the steam within the definition of a public utility. Similarly, the Commission has also ruled that the sale of landfill gas to a single customer is not a sale "to or for the public." The Commission has also ruled that the sale of steam to as many as five industries in an industrial park would not cause the party selling the steam to be a public utility (in Re Request for Declaratory Ruling by Westmoreland-

LG&E Partners, Docket No. SP-100, Sub 2, Order on Notice of Amended Information and Request for Declaratory Ruling (October 13, 1993)); nor would the sale of water to the Town of McAdenville on a wholesale basis by an entity cause the selling entity to be a public utility (in Re Request for Declaratory Ruling by Pharr Yarns, LLC, Docket No. W-1260, Sub 0).

The Commission has examined each of the past instances cited by the Applicants where the Commission held that the sale of a commodity to another did not cause the entity to become a public utility. It is noteworthy that in a substantial majority of those decisions the Commission expressly provided that the decision that was rendered in that case was not intended as precedent and that any future request for a declaration that a particular entity was not a public utility would be determined from the specific fact set that was being presented in that case. In the remainder of those cases, the Commission stressed the uniqueness of the facts and remained silent as to the precedential value of the decisions. Thus, the cited decisions, while enlightening, provide very little, if any, precedent for the request made in this case.

Even if the Commission had not indicated in a majority of its past decisions that the decisions were not intended to serve as precedent in future cases, the decisions rendered by the Commission in those cases would not be supportive of the Applicants' request in this case. A close review of each of the cited cases reveals the situation presented in each of those cases is factually distinguishable from the situations presented in the Application in two fundamental ways. First, none of the cited decisions considered the provision of telephone services in this State from a historical, regulatory and/or current day statutory perspective. Those cases dealt primarily with landfill gas and steam, two commodities that have not been traditionally regulated by the Commission. Second, none of the cases dealt with a situation where the transaction was between affiliated and/or related entities. In the past, this Commission has subjected such transactions to much more intense scrutiny than the scrutiny that those factual situations were evaluated under. These are but two of many significant distinctions between the cases cited and the situation presented by the facts of this case. Thus, none of those cases can provide the Commission with any guidance on how this Application should be decided.

In its Comments, the Public Staff stated that, in its opinion, under the circumstances described in the Application, CSL would not be a public utility as defined by the statute. According to the Public Staff, CSL would not be a public utility for the following reasons. First, under the master lease, the WIN Companies will have exclusive rights to use the subject assets, including the right to access and affix communications electronic, switching, and other equipment to the distribution systems for the provision, routing and delivery of communications services. Second, the WIN companies would be responsible for all costs related to the subject assets and would continue to be responsible for complying with all federal, state, and local regulatory requirements. Third, subject to G.S. 62-110(f4) and (f5), the WIN ILECs will continue to serve as carriers of last resort in their service areas and to provide and charge appropriate contract and tariff rates to other carriers to fulfill their regulatory obligations to provide collocation and access to network elements. Fourth, no customer accounts will be transferred to CSL and CSL will not hold itself out as offering service to the public. Finally, no regulatory purpose would be served by declaring CSL a public utility.

The Commission agrees with each of the factors cited by the Public Staff in support of its opinion that CSL is not a public utility under the facts presented by the Application. The Commission is particularly persuaded that it should not declare CSL to be a public utility because to do so would serve no regulatory purpose. As the transaction is currently structured, the WIN Companies will continue to be the provider of telephone services to their current customers and will continue to be responsible for meeting all state, federal and local regulatory obligations. Thus, the individual WIN Companies will continue to be the public utility to the customers affected by the transaction for all practical purposes. Given this structure and the assurance provided within the lease agreement that the assets will be used solely by the WIN Companies, there is no regulatory purpose to be served by declaring CSL to be a public utility.

Thus, due to the unique circumstances described above, the Commission concludes that CSL is not a public utility and is not therefore required to apply for and receive from the Commission a CPCN either before or after it acquires the subject assets from the WIN Companies and/or leases those same assets back to Windstream for the exclusive use of the WIN Companies. The Commission does so with the understanding that this ultimate conclusion may be subject to review and revision in the future should the facts upon which the conclusion is based change, the lease agreement be substantially modified by the parties and/or CSL or any of the other parties to the Application allows or permits entities other than the entities identified in the Application (or deemed to be included in the Application) to use and/or benefit from the subject assets.

In the Order Requesting Comments, the Commission asked whether there were additional issues that the Commission might need to address concerning the proposed transfer of assets. The impetus behind this question was to ensure that all aspects of the Application and the proposed transaction would be addressed by the inquiry. In responding to the inquiry, the Public Staff observed that there are certain deficiencies in the Application that must be considered by the Commission to fully respond to the Applicants' request for a declaratory judgment. Specifically, the Public Staff observed that the Applicants failed to list two Commission-certificated WIN Companies in the Application, i.e., Windstream Lexcom Long Distance, LLC, the LD provider, and Windstream North Carolina, Inc., the PSP. Thus, the Application, which purportedly seeks a declaration that the transfer of certain assets from <u>all</u> Commission certificated WIN Companies to CSL does not require Commission approval, was incomplete as a result of this omission. The Public Staff proposed that this omission be rectified by deeming the missing entities as included in the Application and stating that its comments were also applicable to those two entities. In its Reply comments, the Applicants agreed that they failed to list the omitted entities through an inadvertent oversight and requested essentially that the Application be amended to reflect their inclusion. For the reasons stated by the Public Staff, the Commission finds and concludes that both of the previously omitted entities should be deemed included in the Application.[1]

[1] In its Comments, the Public Staff observed that neither the statute nor the Commission Rules addressed the applicability of G.S. 62-111(a) to PSPs. The Public Staff thereafter recommended that the Commission exempt PSPs from the provisions of G.S. 62-111(a) to the extent necessary for the purposes of the transaction proposed pursuant to the Commission's statutory authority set forth in G.S. 62-110(c) to "determine the extent to which such services shall be regulated." The Commission notes, however, that PSPs are currently exempted from the transfer approval requirements set forth in G.S. 62-111(a) by Commission Order issued on January 2, 2004 in Docket No. P-100, Sub 72b. Thus, the PSP is not required to seek Commission approval to transfer its assets to CSL.

Finally, both the Public Staff and the Applicants acknowledge in their comments that the CLP/LD companies and TAI are subject to the provisions of Commission Rule R20-1 and FCC slamming/cramming rules regarding the proposed changes to residential customers' local and long distance preferred telecommunications providers and Commission Rule R21-2 which governs the notice requirements that CLP companies must comply with when transferring customers to TAI. In its comments, however, the Public Staff requests that the Commission remind the Applicants that they are subject to these provisions. The Commission agrees with this recommendation. The Commission therefore expressly reminds these entities that they must comply with the slamming and cramming rules set forth in Commission rules as well as the provisions established by the FCC. Further, the Commission also reminds the CLP entities that they are subject to Commission Rule R21-2 which governs the notice requirements that CLP companies must comply with when transferring customers to TAI.

CONCLUSIONS

After carefully considering the Application for a declaratory ruling that Commission approval is not necessary with respect to the transfer of certain assets currently being held by the WIN Companies to CSL, the comments of the Public Staff and the Reply Comments of the Applicants, based on the unique facts presented by this case, the Commission concludes that:

1. As the proposed transaction is currently structured, the Applicants are not required to apply for and/or receive Commission approval to transfer certain assets currently being held by the WIN Companies to CSL pursuant to G.S. 62-111(a).

2. CSL is not a public utility. CSL is not therefore required to apply for and receive from the Commission a CPCN either before or after it acquires the subject assets from the WIN Companies and/or leases those same assets back to Windstream for the exclusive use of the WIN Companies.

3. Windstream Lexcom Long Distance, LLC, the LD provider, and Windstream North Carolina, Inc., the PSP, are deemed included within this Application. A copy of this Order shall be included in the next available docket number for these entities.

4. The aforementioned conclusions are subject to review and revision should the facts upon which they are based change, the lease agreement be substantially modified by the parties and/or CSL or any of the other parties to the Application allows or permits entities other than the entities identified in the Application and those deemed to be included in the Application to use and/or benefit from the subject assets.

5. The decisions reached by the Commission in this Order turn upon the specific facts of this case and do not establish precedent that will be applied to any other application seeking approval of such a transfer and does not articulate any policy or intention with respect to future applications from any other entity which is subject to the Commission's authority. Future applications seeking exemption from Commission approval authority will be dealt with based upon the specific facts presented by the application.

6. The Applicants are reminded that the CLP/LD companies and TAI are subject to the provisions of Commission Rule R20-1 and FCC slamming/cramming rules regarding the proposed changes to residential customers' local and long distance preferred telecommunications providers and Commission Rule R21-2 which governs the notice requirements that CLP companies must comply with when transferring customers to TAI; and, that TAI must be granted the CLP and LD CPCNs sought in Docket No. P-1570, Sub 0 and Docket No. P-1570, Sub 1, respectively, prior to providing service to any customers.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __13th___ day of October, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

Chairman Edward S. Finley, Jr., and Commissioners ToNola D. Brown-Bland and Don M. Bailey did not participate in this decision.

DOCKET NO. T-4537, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of White Glove Movers, LLC, 510 Gallberry Drive, Cary, North Carolina 27519 - Application for Certificate of Exemption to Transport Household Goods	))))	ORDER RULING ON FITNESS AND SHOW CAUSE PROCEEDING

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, Wednesday, August 20, 2014, at 10:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding, Commissioner ToNola D. Brown-Bland, and Commissioner James G. Patterson

APPEARANCES:

For White Glove Movers, LLC:

Gregory S. Connor, Esq., The Connor Law Group, 2501 Blue Ridge Road, Suite 250, Raleigh, North Carolina 27613

BY THE COMMISSION: On April 7, 2014, White Glove Movers, LLC (the Applicant), 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. The Application named Angela Kay Whipple, Martha Allen Hackney and Toriono Washington as the Applicant's principals.

On April 24, 2014, the certified criminal history record checks for the named principals were filed with the Commission as required by North Carolina General Statute Section (G.S.) 62-273.1 and Commission Rule R2-8.1(a)(3).

On June 18, 2014, the Commission issued an Order Scheduling Hearing for July 21, 2014, requiring the Applicant to appear before the Commission to discuss its application for a certificate. The Order also provided that the Public Staff – North Carolina Utilities Commission (Public Staff) may participate in the hearing on behalf of the using and consuming public.

On June 27, 2014, the Commission issued an Order Rescheduling Hearing. The hearing was then scheduled for July 22, 2014.

On July 17, 2014, the Applicant filed notice with the Commission that its attorney would not be available for the scheduled hearing date and it desired a continuance in the matter.

On July 21, 2014, the Commission issued an Order Rescheduling Hearing and Establishing Show Cause Proceeding. The hearing was scheduled for August 2, 2014, and further required the

Applicant and the principals named in the Application, Angela Kay Whipple, Martha Allen Hackney, and Toriono Washington to appear and show cause why they should not be found to have violated the provisions of G.S. 62-280.1 and 62-310 and why they should not be assessed a civil penalty for advertising and operating as a household goods mover without first being issued a certificate by the Commission.

On July 24, 2014, the Public Staff filed notice informing the Commission that it would not participate in the proceeding.

On August 1, 2014, Angela K. Whipple orally informed the Commission that the Applicant's attorney could not be available for the August 5, 2014 hearing. On August 5, 2014, the Commission issued an Order Rescheduling Hearing. The hearing was scheduled for Wednesday, August 20, 2014.

On, August 20, 2014, the hearing came on as scheduled. Gregory S. Connor, Esq., appeared in representation of the Applicant. Angela Whipple and Martha Allen Hackney appeared to provide testimony in support of the Applicant's application. Toriono Washington was not in attendance at the hearing.

On October 16, 2014, the Applicant filed its Proposed Order in the docket.

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

FINDINGS OF FACT

1. On April 2, 2014, the Applicant filed an application for a certificate to operate as a household goods mover in the State of North Carolina. The Applicant identified the following three individuals as its principals: Angela Kay Whipple, Martha Allen Hackney, and Toriono Washington.

2. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

3. Applicants who seek to perform intrastate transportation of household goods for compensation in North Carolina must obtain a certificate pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

4. The Applicant has filed the required confidential criminal history record checks and exhibits.

5. The Applicant is properly before the Commission, pursuant to Commission Rule R1-4(3).

6. Martha Allen Hackney and Toriono Washington were erroneously listed as principals on the application. Angela K. Whipple is the sole principal.

7. Neither Mr. Washington nor Ms. Hackney holds any ownership interest in the Applicant. Mr. Washington was an employee of the Applicant for about a year and a half. He was paid $15 an hour to perform moves. Mr. Washington had seven years of experience in the household goods moving industry. He was the point person for the company and had encouraged Ms. Whipple to pursue an interest in the moving industry. Ms. Hackney is Ms. Whipple's mother and has no involvement with the day-to-day operations of the business.

8. Mr. Washington was fired by Ms. Whipple because, according to her, he misappropriated gas money from the Applicant. After his dismissal from the company, also according to Ms. Whipple's testimony, Mr. Washington failed to return some of the Applicant's moving resources, such as numerous moving blankets, keys to a moving truck, and several hand trucks.

9. In 2013, the Applicant applied for a number from the Federal Department of Transportation in order to operate.

10. The Applicant purchased two box trucks to perform moves. One of the trucks is inoperable and needs considerable work, while the other truck is operational and has been used to perform three moves in the past. The Applicant has obtained general liability insurance on its box trucks with Farm Bureau Insurance Company. Before it purchased its own trucks, Applicant rented U-Haul trucks to perform earlier moves.

11. The Applicant made its first move in April 2013. Since that time, the Applicant has performed a total of twenty intrastate moves. The Applicant did not rely on information from the Commission's Maximum Rate Tariff (MRT) to facilitate its moves. Instead, the Applicant charged its customers $98 an hour for two men to perform a move. The charge increased depending on the size of the job.

12. In April 2014, the Applicant received electronic mail (e-mail) from the Public Staff advising it to cease advertising as a residential and commercial moving company because the Applicant did not possess a certificate from the Commission to perform household goods moves throughout the state for compensation.

13. On April 7, 2014, the Applicant filed its application with the Commission for a certificate.

14. The Applicant advertised its services on a company website, Craigslist, Facebook, LinkedIn and distributed promotional flyers throughout the Cary area. In its ads, the Applicant claimed it was fully licensed and insured. This claim made by the Applicant was false, at least to the extent that the Applicant had not been certificated by the Commission.

15. In May 2014, the Public Staff contacted the Applicant, a second time, to inform the Applicant that it was in violation of the law if it did not make changes to its advertising. At that time, the Applicant removed its ads from Craigslist and stopped distributing promotional flyers in Cary.

16. In May 2014, the Applicant received a letter acknowledging Application from the Commission. In the acknowledgment, Applicant was advised it was not to operate as a household goods mover without a certificate.

17. Even after receiving notification from the Public Staff to amend its advertising, the Applicant's website was never amended or taken offline. The Applicant's website is identified as www.whiteglovemovesllc.com. The website was still up and active as of July 17, 2014. The information on the website stated: "White Glove Movers, LLC, is a residential and commercial moving company in Cary, North Carolina, that handles moves both locally and nationwide." The ad also stated that the Applicant is "fully licensed and insured." Further it asserted that the Applicant performs "Local Moves" and "offers you a full line of home moving and relocation options." The Applicant's website also contained several testimonials from customers about moves that it had performed.

18. A Facebook page was established on behalf of the Applicant by Toriono Washington. The page advertised the Applicant's services as a household goods mover. According to Ms. Whipple's testimony, Mr. Washington is the sole administrator of the page and she has no access to it. As of July 28, 2014, the Facebook page was still active.

19. As of August 8, 2014, Ms. Whipple was still advertising the Applicant's services on her LinkedIn page. The information states that she owned the Applicant since February 2011 to present. This information was false. On cross-examination by the Commission, Ms. Whipple admitted that the company was not formed and established at that time. It was not until 2013, that the Applicant was registered with the Secretary of State. Ms. Whipple testified that she used the 2011 date on her LinkedIn page to cover-up a gap in her employment history.

20. Ms. Whipple has identified two experienced candidates who can be hired by the Applicant to replace Mr. Washington. The candidates possess considerable experience in the household goods moving business. One of the candidates has over 27 years of experience; the other candidate has over ten years of experience.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

(a) Whether the Applicant should be found to be a de facto public utility by holding itself out as a common carrier of HHG, as defined in G.S. 62-3(7)?

The facts in the record show that the Applicant should be found to be a de facto public utility. The Applicant held itself out as a common carrier of household goods as defined in G.S. 62-3(7). The Applicant has been operating since 2013. From 2013 through at least August 8, 2014, the Applicant advertised its services on social media, the internet, and through promotional flyers in the Cary area. The Applicant advertised itself as a lawfully licensed and insured mover of household goods. Ms. Whipple admitted during cross-examination from the Commission that this claim was a false statement. However, this misleading advertisement by the Applicant was sufficient to induce the general public to seek-out its services. The Applicant admits to having performed approximately twenty (20) intrastate moves since it began operating. In fact, there are testimonials on its website by customers indicating that the Applicant performed household goods moves for compensation. According to witness Whipple, the Applicant charged customers $98 an hour for two men to perform a move. The charge for a move increased depending on the size of the move. The Applicant rented U-Haul's to perform moves before it eventually purchased its own box trucks. When the Applicant performed these moves, it did not have a certificate from the Commission. A certificate is required in order to perform a lawful household goods move for compensation in this state.

(b) Whether the Applicant should be subject to sanctions or penalties provided by G.S. 62-310(a), recoverable by the Commission pursuant to G.S. 62-312?

G.S. 62-310 provides that a utility which violates a provision of Chapter 62 or a rule of the Commission may be required to forfeit or pay a sum up to one thousand dollars ($1,000) for each offense. The Commission finds that although the Applicant operated in violation of G.S. 62-3(7) its actions were not willful. The record shows that the Applicant was incorporated in February 2013. At that time, Ms. Whipple had consulted counsel about the company and the purpose behind its formation. At no time did counsel advise Ms. Whipple of the need to apply to the Commission for a certificate of exemption. Ms. Whipple did seek to obtain a number from the Federal Department of Transportation. She erroneously believed that the federal number would be sufficient to perform any move. However, once she was contacted by the Public Staff in April 2014 and advised of the need to secure a certificate from the Commission, the Applicant ceased operations and filed an application including the proper background information. Based on the foregoing, the Commission finds that a civil penalty should not be assessed upon the Applicant in this instance.

(c) Whether the Applicant should be found to have violated G.S. 62-280.1, by advertising its services on the internet as a household goods carrier to the public without first having been issued a certificate of exemption from the Commission?

G.S. 62-280.1 states, in pertinent part, that it is unlawful for a person not issued a certificate to operate as a carrier of household goods by orally, in writing, in print, or by internet represent that the person holds a certificate or otherwise is authorized to operate as a carrier of household goods in this state.

Based on the facts in the record, the Commission concludes that the Applicant violated G.S. 62-280.1. The Applicant began advertising its services in March 2013. Since that time, the Applicant has held itself out as a certificated carrier through the following methods of advertising: First, the Applicant advertised its services on a website at www.whiteglovemovesllc.com. The website states that "White Glove Movers, LLC, is a residential and commercial moving company in Cary, North Carolina, that handles moves both locally and nationwide." The site further states that the Applicant is "fully licensed and insured." The website also contains several testimonials from customers about moves that the Applicant performed. Second, the Applicant's services were advertised on Facebook[1]. Third, the Applicant advertised its services on Craigslist[2]. The Applicant's ads on Craigslist contained similar information that was highlighted on its website.

[1] Facebook is a social networking website that allows its participants to share information with other account holders.

[2] Craigslist is a free on-line service that allows members of the general public to post classified ads for services, including but not limited to housing, moving, and employment to name a few.

Fourth, the Applicant's services were advertised on Ms. Whipple's LinkedIn[1] page that was placed on the internet. On her LinkedIn page, Ms. Whipple states that she is the president and owner of the Applicant. She further indicates that the Applicant was incorporated and began operating as a household goods mover in February 2011. Her claims, however, that the Applicant was incorporated and performing household goods movers since 2011 were false. Finally, the Applicant advertised its moving services and rates through promotional flyers that were distributed throughout the Cary area by Ms. Whipple or a designee of Ms. Whipple's.

The record further shows that all of the above-cited advertising occurred prior to the Applicant obtaining a certificate from the Commission. The Applicant did not file an application with the Commission for a certificate until April 2014. According to Ms. Whipple's testimony, the Applicant began performing intrastate moves in April 2013. Since that time, it publicly advertised its services and performed about twenty (20) moves in the state. As of the date of the hearing, the Applicant still had not been issued a certificate from the Commission.

(d) Whether the Applicant should be subject to sanctions and/or penalties provided by G.S. 62-280.1(c), recoverable pursuant to G.S. 62-312?

In April 2014, the Public Staff contacted Ms. Whipple and advised her that the Applicant was in violation of the law by advertising its services as a household goods mover because it did not possess a certificate from the Commission and advised her to amend the advertisements. At that time, the Applicant was placed on notice that there was a problem with its activities. Ms. Whipple testified that it was not until after she received a second call from the Public Staff that she actually acted to remove the Applicant's ads on Craigslist and stopped distributing promotional flyers in the Cary area. However, Ms. Whipple did not address the Applicant's other advertising methods.

On June 28, 2014, the Commission discovered a Facebook page that features the Applicant as a business that provides various services including household goods moving. Ms. Whipple asserts that she has no control over the page and is unable to dictate what it contains. She claims that Mr. Toriono Washington has control of the Facebook page and she is unable to take it down. The Commission finds it unlikely that Ms. Whipple was unaware that the site was initially established for the Applicant. Moreover, it is clear from Ms. Whipple's testimony and history of the Applicant's formation as a business that the advertising was for the benefit of the Applicant. The record supports the fact that the Applicant had sufficient time to resolve the advertising problem but did not act in a diligent manner to do so.

Based on the foregoing, the Commission finds and concludes that from the time it was notified by the Public Staff that it was in violation of applicable law, the Applicant acted willfully in this matter and therefore, it should be assessed a civil penalty, as provided by G.S. 62-280.1(c) for advertising its services on the internet. The Commission finds that a civil penalty of one thousand dollars ($1,000) is a sufficient penalty based on the advertising conducted by the Applicant.

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[1] LinkedIn is the world's largest professional network on the internet. The website boasts more than 300 million members worldwide.

(e) Whether Ms. Angela K. Whipple's fitness should prohibit the Applicant from being issued a certificate?

The evidence in the record shows that Ms. Whipple is the president and sole manager of the Applicant. Ms. Whipple started the business as a method to increase her income. The company was established in 2013. She obtained experience in the household goods industry when the business began operating in 2013. Beginning in 2013, Ms. Whipple handled all the administrative paperwork for the moves that were performed by the Applicant. Specifically, she prepared the estimates for the moves and bills of ladings. Ms. Whipple also possesses over fifteen years of experience in finance, payroll production and preparation of tax documents. She plans to supplement her knowledge by hiring someone with more experience in household goods moving than she has. At present, Ms. Whipple has identified two candidates to replace Mr. Washington. Each candidate possesses over seven years of experience in the moving industry. The new hire will be responsible for coordinating the moves including boxing/wrapping, loading, and transporting the goods to their destinations. In preparation of operating her moving business, Ms. Whipple purchased two box trucks. These trucks are insured by Farm Bureau Insurance. According to the Applicant's financial documents, it has sufficient cash on hand to operate its day-to-day moving business.

Based on the foregoing, the Commission finds and concludes that the Applicant is fit and willing to perform service as a household goods mover. The Commission, therefore, requires that either Ms. Whipple or another of the Applicant's staff attend and participate in MRT training within ninety (90) days after issuance of its certificate of exemption. In addition, in order to assure compliance with applicable law, the Commission strongly recommends that the Applicant (Ms. Whipple or another representative of the Applicant) consult with the Public Staff prior to performing its first intrastate move. The Public Staff will be able to provide the Applicant with important information such as the proper method of estimating the cost of the move, how to properly secure household goods, how to complete an approved bill of lading, and provide insight on how to resolve consumer complaints.

OTHER CONCLUSION

The Commission further understands that the Applicant has ended its working relationship with Mr. Washington, a former employee. In fact, the Applicant has made various claims that Mr. Washington has illegally retained equipment that belongs to the company. In response, Ms. Whipple has indicated that she has notified local law enforcement in an effort to retrieve the illegally seized property. Given Mr. Washington's alleged actions, the Commission finds and concludes that, as a condition of receiving a certificate from the Commission, the Applicant shall not employ Mr. Washington in any capacity with the company. Additionally, the Commission finds and concludes that if there is any change in the ownership/management structure of the Applicant, it shall notify the Commission in writing within thirty (30) days of any such change, so that its status can be reviewed.

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant shall not pay a civil penalty for operating as a de facto public utility without first obtaining a certificate.

2. That the Applicant shall pay a civil penalty of one thousand dollars ($1,000) to the Commission, Office of the Chief Clerk, for its violations of G.S. 62-280.1(a).

3. That the total one thousand dollars ($1,000) civil penalty assessed hereby shall be payable, no later than ninety (90) days from the date of this Order, to the North Carolina Department of Commerce/Utilities Commission.

4. That the Applicant shall be eligible to receive its certificate once it has fully complied with the civil penalties assessed by the Commission and it has been notified by the Commission that it has complied with all other requirements for a certificate of exemption.

5. That, as a condition of receiving and maintaining a certificate from the Commission, the Applicant shall not employ Mr. Toriono Washington in any capacity with the company.

6. That if there is any change in the Applicant's ownership/management structure, it will notify the Commission in writing within thirty (30) days of any such change, so that its status can be reviewed.

7. That the Applicant shall be served with this Order by United States certified mail, return receipt requested and electronic mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the __5th____ day of November, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige Morris, Deputy Clerk

DOCKET NO. T-4523, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of S.J. (Bill) Hopper, 3333 Knighton Lane, Gastonia, North Carolina 28056, Complainant v. Pick Up and Go Moving International, 9815 J Sam Furr Road, Suite 27, Huntersville, North Carolina 28078, Respondent	)	ORDER SCHEDULING HEARING, CLARIFYING ISSUES FOR HEARING, AND DISMISSING CLAIM, IN PART

BY THE PRESIDING COMMISSIONER: On May 19, 2014, Complainant filed notice that he has reviewed Respondent's Answer in the docket, is not satisfied with the Answer and requests a hearing to present evidence in support of his Complaint.

On May 28, 2014, the Commission issued an Order Serving Complainant's Reply on Respondent. The Order allowed Respondent until June 11, 2014, to review the notice and make a further filing, if any, prior to the Commission taking further action in the docket. Respondent has not made any filing in the docket after issuance of the Order.

The Presiding Commissioner has reviewed the record and has determined that Complainant seeks the following relief:

1. Reimbursement for November storage ($300.00) paid up front by Complainant since agreement to move furniture from storage into the Gastonia residence was agreed to by Complainant and Tony Johnson (Respondent's employee) for October 31;

2. Reimbursement for monies overcharged Complainant (the difference between the website price quoted versus actual dollar amount charged/billed);

3. Order ensuring Pick Up and Go Moving International either makes repairs on all documented damage or reimburses Complainant for the appraised value for those pieces that cannot be repaired;

4. Order ensuring base to Tiffany lamp is returned to Complainant;

5. Order ensuring Pick Up and Go Moving International has all obligations completed by a time certain set by the Commission, with respect to removing damaged pieces from 3333 Knighton Lane, Gastonia, North Carolina 28056;

6. Order assessing Pick Up and Go Moving International the maximum fine and associated penalties for moving Complainant without a license;

7. Order assessing Pick Up and Go Moving International the maximum fine and associated penalties for any other documented moves without a license;

8. Order assessing Pick Up and Go Moving International an additional fine for violation of G.S. 62-280.1- advertising as a mover without a certificate; and

9. Denial of Pick Up and Go Moving International's application for a certificate of exemption for the transportation of household goods.

The Commission does not have jurisdiction to grant the requested relief in its entirety. In particular, the Commission does not have jurisdiction to grant Complainant's request for repairs on all documented damage or reimbursement for appraised value on items that cannot be repaired. The Commission has long acknowledged that it lacks jurisdiction to award damages. *See* *State of North Carolina ex rel. Utilities Commission v. Thrifty Call, Inc.*, *154 N.C.App. 58, 571 S.E.2d 622 (2002). See also* *State ex rel. N.C. Corporation Commission v. Southern Railway*, *147 N.C. 483, 61 S.E. 271 (1908).* Complainant can seek remedy for monetary damages in a Court of General Justice in the county where he resides. Accordingly, Complainant's claim for repair and reimbursement relief is dismissed without prejudice to Complainant's right to pursue said claim in the General Court of Justice.

The Commission, however, does have jurisdiction over the remainder of the issues raised expressly or impliedly by the Complaint. Specifically, the Commission has jurisdiction to decide the following:

(1) Whether Complainant is entitled to a reimbursement of the fees he paid to Respondent for the storage of furniture and any rates that were paid to Respondent for the alleged move of Complainant's household goods;

(2) Whether Respondent is responsible for returning any items still held after completion of the alleged move of Complainant's furniture;

(3) Whether Respondent is responsible for removing any damaged goods still remaining at Complainant's residence;

(4) Whether Respondent should be found to be a de facto public utility by holding itself out as a common carrier of household goods, as defined in G.S. 62-3(7), and by engaging in intrastate commerce as set forth in G.S. 62-3(15) in June 2013;

(5) Whether Respondent violated North Carolina Law and Commission Rules by operating without a certificate of exemption in violation of G.S. 62-261(8) and Commission Rule R2-8.1, and by moving Complainant's household goods from Mooresville, North Carolina, to Gastonia, North Carolina, in July and November 2013;

(6) Whether Respondent should be assessed sanctions and/or civil penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312, and/or have its license plates revoked or suspended pursuant to G.S. 62-278(a) for any violations of the laws or rules as alleged by Complainant;

(7) Whether Respondent violated G.S. 62-280.1 by advertising its moving services on the internet without first having obtained a certificate of exemption; and

(8) Whether, in light of Complainant's allegations, Respondent is fit to be granted a certificate of exemption from the Commission to perform the service of transporting household goods within the state of North Carolina.

After a careful review of the record, the Presiding Commissioner finds that good cause exists to schedule this docket for hearing on the issues identified above. Pursuant to G.S. 62-75, the burden of proof in this matter rests upon Complainant to present evidence to support the allegations made in the Complaint. Complainant may attempt to meet this burden by offering testimony, witnesses, and/or documents which support his claim.

IT IS, THEREFORE, ORDERED as follows:

1. That the docket is scheduled for hearing on Tuesday, September 23, 2014, 1:00 p.m., Gaston County Courthouse, 325 N. Marietta Street, Courtroom 4D, Gastonia, North Carolina 28052.

2. That Pick Up & Go Moving International shall retain legal counsel, as required by Commission Rule R1-22, to represent it before the Commission in this proceeding.

3. That, for lack of jurisdiction, Complainant's claim for repair and reimbursement relief is hereby dismissed without prejudice to Complainant's right to bring such claim in the General Court of Justice.

4. That the Chief Clerk shall serve a copy of this Order on Pick Up & Go Moving International by means of United States certified mail, return receipt requested and by electronic mail (e-mail), delivery confirmation requested.

5. That the Chief Clerk shall serve a copy of this Order on Complainant by means of United States certified mail, return receipt requested.

ISSUED BY ORDER OF THE COMMISSION.
This the _14th__ day of August 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. T-4353, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Criminal History and Citizenship/Employment Authorization Update Form for Principle of Absolute Moving & Storage, Inc., Post Office Box 805, Holly Ridge, North Carolina 28445	)))))	ORDER RULING ON COMPLIANCE FILING

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Thursday, November 7, 2013, at 10:00 a.m.

BEFORE: Commissioner Bryan E. Beatty, Presiding; Commissioner Susan W. Rabon, and Commissioner Jerry C. Dockham.

APPEARANCES:

For Anthony Duckworth, d/b/a Absolute Moving & Storage, Inc.:

Lonnie P. Merritt, Lonnie P. Merritt Law Firm, Post Office Box 2240, Wilmington, North Carolina 28402.

BY THE COMMISSION: On April 16, 2012, Mr. Anthony Dean Duckworth (Mr. Duckworth), the company principal of Absolute Moving & Storage, Inc. (Absolute), filed with the North Carolina Utilities Commission (Commission) his “Principal’s Criminal History and Citizenship/Employment Authorization Update Form” (Update Form), as required by the Commission.

On August 29, 2013, the Commission issued an Order Scheduling Hearing in the above-captioned proceeding. In the Order, Mr. Duckworth was required to appear before the Commission and answer questions on the information in the criminal history update form which he submitted to the Commission in 2012. The hearing was scheduled for November 7, 2013, in Raleigh, North Carolina.

On November 7, 2013, the matter came on for hearing as scheduled. Mr. Duckworth appeared with counsel, Lonnie P. Merritt, to testify and answer questions from the Commission about himself and Absolute. Mr. Duckworth also submitted exhibits into the record.

Prior to the taking of testimony, the Presiding Commissioner explained to Mr. Duckworth that Commission procedures provide for confidentiality with regard to matters involving his criminal history record check originally submitted to the Commission in 2007 and any information submitted pursuant to his 2012 criminal history update form. After consultation with counsel, Mr. Duckworth waived confidentiality as to two other persons present in the hearing room, all other persons were asked to leave the hearing room.

On December 13, 2013, Mr. Duckworth filed his Proposed Order.

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

FINDINGS OF FACT

1. The Commission has jurisdiction over public utilities, including those engaged in the intrastate transportation of household goods for compensation in North Carolina, as defined by G.S. 62-3(7) and (15).

2. The Commission has authority to issue certificates to applicants for the purpose of intrastate transportation of household goods for compensation in North Carolina, pursuant to G.S. 62-261(8) and Commission Rule R2-8.1.

3. Absolute was issued a certificate to operate as a household goods mover by the Commission on or about January 27, 2007.

4. Absolute has operated as a mover continually since that time, making three or four hundred moves per year, with six or seven full-time and three part-time employees.

5. Anthony Dean Duckworth is principal and owner of Absolute. He employs a job foreman to take care of the paperwork and client billing in the field. Mr. Duckworth performs administrative work such as providing clients with job estimates. He also travels to the job site to check the employees work and to make sure that the client is satisfied with the company's work. Mr. Duckworth is responsible for resolving any disputes involving the company.

6. Mr. Duckworth's wife is also employed with Absolute where she does office work, bookkeeping and accounting.

7. Absolute has recently purchased two new moving trucks (a 2014 Freightliner, and a 2014 Hino). Additionally, the company is planning to build a 10,000 square feet warehouse in Holly Ridge, North Carolina.

8. Absolute has an A-plus rating with the Better Business Bureau (BBB). The company has a good reputation with its customers. The company builds its business through repeat customers and referrals.

9. There have been no complaints filed against Mr. Duckworth or Absolute with the Commission or the BBB.

10. Mr. Duckworth noted a change in his criminal history in his 2012 Annual Criminal History and Citizenship/Employment Authorization Update Form filed with the Commission on April 16, 2012.

11. The incident which Mr. Duckworth noted on his update form occurred on December 24, 2009. The incident was not related to the operations or customers of Absolute.

WHEREUPON, the Commission reaches the following:

CONCLUSIONS

The Commission's responsibility to evaluate an applicant's fitness does not end once a certificate is issued to the applicant. This evaluation process is ongoing and an applicant's or current certificate holder's status can be reviewed at any time. *See N.C.U.C. Dkt. No. T-100, SUB 69* (August 29, 2008). This is the primary reason that the Commission has required that applicant's and current certificate holders provide notification of any changes in their status after obtaining a certificate. This change in status is also true with regard to an applicant's criminal history. In order to continue in its efforts to protect the using and consuming public, the Commission must have the new information and uncover why it has changed.

The Commission in this docket obtained information relevant to Mr. Duckworth's criminal history as disclosed to the Commission in Mr. Duckworth's 2012 annual Criminal History and Citizenship/Employment Authorization Update Form filed by Mr. Duckworth on April 16, 2012. This information called into question Mr. Duckworth's fitness to continue to operate as a household goods mover in the state of North Carolina. Consequently, the Commission conducted a hearing to probe Mr. Duckworth's fitness.

The Commission considers a number of factors regarding the reported offense in making its 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.

The evidence presented during the hearing shows that Absolute has been successful as a company since it received a certificate from this Commission in 2007. Specifically, the company has purchased several new trucks, is building a 10,000 square feet warehouse in Holly Ridge, NC, planning to increase its staff, and there have been no complaints filed against it with the Commission or the Better Business Bureau. Finally, the Commission has reviewed the information included on Mr. Duckworth's 2012 Update form and determined that the incident was **not related** to the operations or customers of Absolute.

Based upon the entire record including the testimony, which was uncontested, the Commission concludes that Mr. Anthony Dean Duckworth should be allowed to continue to operate as a household goods mover in the state of North Carolina despite the information provided on his 2012 annual Criminal History and Citizenship/Employment Authorization Update Form filed by Mr. Duckworth on April 16, 2012.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _23rd_ day of January, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. T-4552, SUB 0
DOCKET NO. T-4510, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-4552, SUB 0 In the Matter of Christopher N. Wilhoit, d/b/a A Magic Move, Inc., 1307 South 41st Street, Wilmington, North Carolina 28403 – Unlawful Representation of Authority and Unauthorized Transportation of Household Goods and DOCKET NO. T-4510, SUB 2 In the Matter of Samantha Lynn Piner, d/b/a Miracle Movers, 513 E. Lanier Street, Wallace, North Carolina 28466 - Unauthorized Use of Operating Rights	ORDER ACCEPTING CONSENT AGREEMENT

BEFORE: Commissioner Bryan E. Beatty, Presiding, Commissioner ToNola D. Brown-Bland, and Commissioner Don M. Bailey

BY THE COMMISSION: On September 9, 2014, the Public Staff-North Carolina Utilities Commission (Public Staff) by and through its Executive Director, Christopher J. Ayers, filed with the North Carolina Utilities Commission (Commission), a Petition for Show Cause in the above-captioned proceedings. By Order of the Commission on October 30, 2014, Christopher Wilhoit, d/b/a A Magic Move, Inc. (A Magic Move), and Samantha Lynn Piner, d/b/a Miracle Movers (Miracle Movers), were both directed to appear before the Commission and show cause. For A Magic Move, the Commission directed it to appear and show cause (a) why it should not be found to have represented itself as holding a certificate of exemption (certificate) and otherwise authorized to operate as a carrier of household goods in North Carolina in violation of G.S. 62-280.1(a) and assessed a civil penalty not in excess of five thousand dollars ($5,000) for such violation; and (b) why it should not be found to be a de facto public utility by holding itself out as a common carrier of household goods, as defined in G.S. 62-3(7), while engaging in the intrastate transport of household goods without possessing a certificate as required by G.S. 62-261(8) and Commission Rule R2-8.1 in violation of G.S. 62-262(a) and subject to sanctions or penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62312. As for Miracle Movers, the Commission ordered Ms. Piner to appear and show cause why she should not be found to have permitted her name or operating rights to be used by A Magic Move, in violation of Commission Rule R2-24 and subject to sanctions or penalties provided by G.S. 62-310(a), recoverable pursuant to G.S. 62-312.

On December 16, 2014, the Public Staff filed a Motion to Cancel Hearing. Attached to the Motion was the Consent Agreement executed between the Public Staff, A Magic Move, and Miracle Movers (collectively, "the Parties"). The hearing was canceled by order of the Commission on December 17, 2014.

WHEREUPON, the Commission makes the following:

CONCLUSIONS

The Commission has reviewed the Consent Agreement filed by the Parties in these proceedings and makes the following findings and conclusions with regard to the Agreement executed by the Parties. Pursuant to the Agreement, A Magic Move, through its president, Christopher Wilhoit, admits it is in the business of transporting household goods and that it has neither applied for nor been issued a certificate of exemption by the Commission to engage in the intrastate transport of household goods. A Magic Move further admits that it has been previously contacted by the Public Staff and informed of the requirements to make application for a certificate with the Commission and advised of the illegal content of its advertising. A Magic Move advertised its services indicating that the company provides intrastate transportation of household goods on the internet on its website at www.wilmingtonmovingcompany.org and on social media at www.facebook.com/AMagicMove. A Magic Move's actions were clear violations of G.S. 62-262(a) and G.S. 62-280.1, which prohibit an entity from representing that it is authorized to perform intrastate household good moves without first obtaining a certificate from the Commission and advertising that one provides such moving services in the absence of such certification.

Per the terms of the Consent Agreement, A Magic Move has agreed to pay a total monetary fine of one thousand dollars ($1,000.00) in United States currency to the Commission.[1] The total fine is comprised of five hundred dollars ($500.00) for violation of G.S. 62-262(a) and five hundred dollars ($500.00) for violation of G.S. 62-280.1. The Agreement provides that the monetary fine will be due in five equal installments; the first is to be paid ten days after issuance of this Order. The remaining payments will be due each month on the same day of the subsequent months.

Also pursuant to the Consent Agreement, Miracle Movers, through its owner, Samantha Lynn Piner, admits that it has violated Commission Rule R2-24 by permitting its name to be used by A Magic Move in advertising to solicit customers for household goods moves in the State. According to the terms of the Agreement, for this violation, Miracle Movers has agreed to pay a monetary fine of five hundred dollars ($500.00) in United States currency to the Commission. The Agreement provides Miracle Movers may pay this fine in two payments of two hundred fifty dollars ($250.00). The first installment of two hundred fifty dollars ($250.00) is to be paid ten days after the issuance of this Order, with the subsequent installment due the same day of the subsequent month.

[1] The proceeds from civil penalties paid to the Commission go to the county for public schools.

In this case, the Commission supports the assessment of monetary penalties against A Magic Move and Miracle Movers based on their admitted illegal actions. The Commission considers the assessment of monetary fines an effective mechanism to deter others from engaging in such deviant behavior. The Commission notes, however, that had A Magic Move and Miracle Movers not agreed to the stated fines, they faced the possible imposition of greater fines and/or other sanctions for their violations of North Carolina law and Commission Rules.

The Commission admonishes A Magic Move and Miracle Movers to abide by all applicable laws and the rules and regulations of the Commission. In the future, should the Commission have reason to believe that either or both of the entities party hereto has engaged or is engaging in any further unauthorized activities, the appropriate steps will be taken to bring them in for additional enforcement. The Commission takes its obligation to protect the using and consuming public from uncertificated and/or offending movers seriously. The Commission will continue to pursue enforcement of its rules and North Carolina law, particularly where there is sufficient evidence establishing that entities have ignored the advice and guidance of the Public Staff and/or have not acted in a timely manner to remedy potential violations.

Based upon the foregoing, the Commission finds and concludes that good cause exists to accept the Agreement executed by the Parties and filed with the Commission on December 16, 2014. The Commission further finds and concludes that good cause exists to take no further action in these proceedings until such time that A Magic Move and Miracle Movers fully complete their financial obligations under the Agreement. Upon the fulfillment of these obligations, the Commission will issue an order dismissing the proceedings and close both dockets.

IT IS, THEREFORE, ORDERED as follows:

1. That A Magic Move will pay a total monetary fine of one thousand dollars ($1,000.00) in United States currency to the North Carolina Utilities Commission. The total fine is comprised of five hundred dollars ($500.00) for violation of G.S. 62-262(a) and five hundred dollars ($500.00) for violation of G.S. 62-280.1. This monetary fine will be due in five equal installments; the first is to be paid ten days after issuance of this Order. The remaining payments will be due each month on the same day of the subsequent months.

2. That Miracle Movers will pay a total monetary fine of five hundred dollars ($500.00) in United States currency to the Commission. Miracle Movers may pay this fine in two payments of two hundred fifty dollars ($250.00). The first installment of two hundred fifty dollars ($250.00) is to be paid ten days after the issuance of this Order, with the subsequent installment due the same day of the subsequent month.

3. That these proceedings will remain open until A Magic Move and Miracle Movers fully complete their financial obligations under the Agreement. Upon fulfillment of these obligations, the Commission will issue an Order dismissing the proceedings and closing the dockets.

4. That this Order will be served on A Magic Mover and Miracle Movers by United States certified mail, return receipt requested and electronic mail (e-mail), delivery confirmation requested.

5. That this Order will be served on the Public Staff by e-mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the _29th_ day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. W-1160, SUB 22

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of CPG FINANCE I LLC Complainant, v. KDHWWTP, LLC Respondent.	)))))))	ORDER RULING ON COMPLAINT

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on May 18-19, 2014

BEFORE: Commission Chairman Edward S. Finley, Jr., Presiding; Commissioner Bryan E. Beatty, and Commissioner Don M. Bailey.

APPEARANCES:

For CPG Finance I LLC:

M. Keith Kapp and Jennifer A. Morgan, Williams Mullen, 301 Fayetteville Street, Suite 1700, Raleigh, NC 27601

For KDHWWTP, LLC:

Robert F. Page, Crisp, Page, & Currin, LLP, 4010 Barrett Dr., Suite 205, Raleigh, NC 27609

BY THE COMMISSION: On November 22, 2013, CPG Finance I LLC (CPG or Complainant) filed its Complaint and Petition to require KDHWWTP, LLC (KDH or Respondent) to assume control of, operate, repair, and replace the wastewater pump station located near the northern corner of the Dare Centre shopping center at 1700 North Croatan Highway in Dare County, Kill Devil Hills, North Carolina at the intersection of Third Street and Highway 158 (Dare Centre Pump Station). On November 26, 2013, the Commission issued its Order Serving Complaint, whereby KDH was directed to review the Complaint and to satisfy the demands of the Complainant or to file an Answer with the Commission on or before December 10, 2013.

On December 19, 2013, KDH filed its Request for Extension of Time until January 13, 2014 to file its Answer. On December 23, 2013, the Commission issued an Order extending the time until January 8, 2014 for KDH to file its Answer.

On January 8, 2014, KDH filed its Answer to the Complaint which was served by Commission Order issued January 17, 2014.

On January 28, 2014, CPG filed its Reply to the Answer stating that it was not satisfied with KDH's response and setting forth the basis of objections to be answered and further requesting expedited hearing.

On February 11, 2014, the Commission issued its order Serving the Reply and Scheduling the Docket for Hearing, setting the matter for hearing on March 18, 2014 at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

The matter came on for hearing as scheduled. CPG presented exhibits and testimony of witnesses Ed Zivec, Dana Grimes, and Gina Casselberry. The Commission took judicial notice of the documents contained within CPG Finance's First Request to Take Judicial Notice, Second Request to Take Judicial Notice, and provision 15A, 15A NCAC 08G.0102(g) of the North Carolina Administrative Code. KDH presented the testimony and exhibits of witnesses Al Hodge, Bill Freed, David Hoyle, and Eddie Goodrich.

All parties were given the opportunity to file briefs and proposed orders. The Commission directed the parties to submit post-hearing briefs and proposed orders by May 23, 2014, pursuant to the April 7, 2014 Notice of Due Date for Briefs and/or Proposed Orders and the April 28, 2014 Order Granting Extension of Time.

Based on the foregoing, the evidence presented at the hearing, and the entire record in this matter, the Commission now makes the following:

FINDINGS OF FACT

1. CPG is a limited liability company organized under the laws of Delaware, with its principal place of business in Indianapolis, Indiana. CPG is an affiliate of Simon Property Group, Inc., a commercial real estate company.

2. KDH is a public utility operating under the laws of the State of North Carolina and subject to the jurisdiction of the North Carolina Utilities Commission. KDH is engaged in the business of providing wastewater utility service to the public on the North Carolina Outer Banks.

3. CPG is the lessee/operator of the Dare Centre, a shopping center in Dare County, North Carolina.

4. The Dare Centre Pump Station is a wastewater pump station that is located at the Dare Centre at 1700 North Croatan Highway, near the intersection of Third Street and Highway 158.

5. The Dare Centre and the Dare Centre Pump Station are located on property owned by three individuals, Mark Olivola, Karen Olivola Price, and Nancy Olivola Walton (the Olivolas), who are the principals of The Stella Land and Development Corporation (Stella Land). CPG has a ground lease with The Stella Land and Development Corporation for the Dare Centre.

6. CPG receives wastewater utility service from KDH for the Dare Centre and is a customer of KDH. The businesses that lease space in the Dare Centre from CPG also are customers of KDH.

7. Outer Banks Beach Club, Inc., was a developer at property in Dare County and the utility that was issued the original Certificate of Public Convenience and Necessity in Commission Docket No. W-887, Sub 0 for wastewater utility service to the service area that includes the Dare Centre.

8. On October 20, 1987, in Docket No. W-887, Sub 0, the Commission issued a Certificate of Public Convenience and Necessity to Outer Banks Beach Club, Inc. to provide wastewater utility service to customers in Kill Devil Hills, North Carolina.

9. On August 6, 2001, KDH filed an Application with the Commission in Docket No. W-1160, Sub 0, seeking a Certificate of Public Convenience and Necessity and authority to acquire the utility assets franchised to Outer Banks Beach Club, Inc. These assets had been transferred to Peppertree Resort Villas, Inc., a successor by merger to Outer Banks Beach Club, Inc. (hereafter, OBBCI – not to be confused with the current resort timeshare villas, which is referred to as Outer Banks Beach Club.)

10. As part of its Application, KDH included the Offer to Purchase and Contract for Sale [with Peppertree Resort Villas, Inc., from whom Outer Banks Beach Club, Inc. merged without Commission approval.] The Offer to Purchase Contract was supposed to include an Exhibit B, which was a detailed list of all equipment and facilities comprising the sewage treatment facility and a complete central sewage collection and disposal system, as well as a list of other tangible items such as customer lists, books, and records. However, Exhibit B was not attached.

11. On October 31, 2001, the Commission issued a Recommended Order Approving Transfer and Approving Rates in that docket, made final by an Order Allowing Recommended Order to Become Effective and Final, issued the same date, approving the cancellation of the Outer Banks Beach Club, Inc., certificate and issuing a new Certificate of Public Convenience and Necessity to KDH.

12. In the October 31, 2001 Order, the Commission made Findings of Fact 3 and 4 as follows:

> Peppertree does not currently own or have control of its entire sewage collection system.
>
> The Applicant should be required to acquire ownership of the entire collection system infrastructure within 12 months.

13. Ordering paragraphs 8 and 9 of the October 31, 2001 Order stated:

> That KDHWWTP, LLC, shall address DWQ noncompliance and bring its facilities into full compliance with DWQ regulations within 18 months after transfer.
>
> That KDHWWTP, LLC, shall acquire ownership of the entire collection system infrastructure within 12 months.

14. KDH did not obtain ownership of the entire collection system infrastructure within 12 months or address DWQ noncompliance with its entire collection system infrastructure within 18 months of transfer.

15. The main treatment plant and related collection facilities, in the hands of KDH's predecessor, had fallen into both financial distress and operational disrepair.

16. The system was receiving frequent Notice of Violations (NOVs) from Division of Environment and Natural Resources (DENR) and Division of Water Quality (DWQ).

17. KDH's predecessor's business records were in as poor a state as the wastewater treatment facilities themselves.

18. So as to avoid difficulties with a division of responsibility between the owner of the franchise and the owner of the facilities, such as the Commission faced in the <u>Monterey Shores</u> case near Corolla, the Commission ordered KDH, as a part of its franchise responsibilities, to acquire ownership and control of its entire collection system.

19. In response to the requirements included in paragraphs 8 and 9 of the October 31, 2001 Order, KDH sent a letter to the landowners, including the Olivolas and Stella Land, requesting that the landowners sign a proposed quitclaim bill of sale and easement agreement.

20. KDH did not receive a response from these landowners.

21. As new areas were served, and new pump stations were required, KDH required the customer to construct such pump station facilities and to transfer the ownership of the facilities, together with a suitable easement, to KDH.

22. At that point, KDH sought and received an appropriate operating permit from DWQ for the new pump stations.

23. KDH also achieved a transfer of the operating permits for those pump stations that had clearly been owned by the predecessor utility, i.e., OBBCI.

24. On February 8, 2010, the Commission ordered an investigation into the status of ownership and responsibility for the pump station located at the intersection of Virginia Dare Trail and Calvin Street. As part of that investigation, the Commission was requested to review the status of ownership of 17 other "orphan" pump stations, including the Dare Centre pump station, which is interconnected with KDH's wastewater collection system, but for which KDH had not accepted ownership or responsibility.

25. The parties to that docket were the Public Staff, KDH, Outer Banks Beach Club Association and Outer Banks Beach Club II Owners Association (Outer Banks Beach Club Associations or OBBC), and Wyndham Vacation Ownership, Inc. (WVO).

26. In 2010-2011, pursuant to a petition filed by the Public Staff, KDH attempted to litigate a matter (Docket No. W-1160, Sub 10) involving responsibility for payment for the replacement of the pump station serving the Outer Banks Beach Club Timeshare Resort Villas.

27. That pump station was also one of the "orphan" pump stations.

28. The predecessor utility and the Resort Villas, then under the common ownership of Peppertree Resorts, had gone into bankruptcy, and it simply was not clear who owned or had the responsibility to operate the OBBC pump station.

29. According to KDH, it was willing to assume this responsibility but believed that the owners of the Resort Villas should pay some or all of the cost of replacement since they alone, of all of KDH's customers, had not paid anything towards the recovery of capital costs for the new wastewater treatment plant which KDH built and which was then serving the OBBC Resort Villas.

30. The Olivolas, Stella Land and CPG were not parties to the proceeding and did not sign the agreement that resulted in an order issued by the Presiding Commissioner on May 10, 2011 in Docket No. W-1160, Sub 10.

31. On May 9, 2011, the parties in that case filed a Joint Motion of Proposed Settlement and Joint Proposed Order, which would set forth a process by which KDH would take ownership of all the "orphan" pump stations.

32. On May 10, 2011, in Docket No. W-1160, Sub 10, the Presiding Commissioner issued an Order Granting Joint Motion and Continuing Hearing (the May 2011 Order).

33. The May 10, 2011 Order approved the agreement setting forth the process by which KDH would take ownership of the orphan pump stations.

34. In that May 2011 Order, the Presiding Commissioner indicated that KDH should bear the full cost responsibility for replacing the old OBBC pump station.

35. Finding of Fact 10 of the May 2011 Order provided in relevant part:

> That KDH, after completion of the major renovations or replacement of the Disputed Pump Station, shall begin in order of priority the necessary renovations to the 17 other wastewater pump stations connected to KDHWWTP's wastewater collection system that KDHWWTP described as "orphan" pump stations in Appendix A attached to the Joint Motion to Hold Matter in Abeyance filed on February 23, 2011, with the priority being likelihood of failure during tourist seasons on the Outer Banks. KDHWWTP shall be solely responsible for the costs of the necessary renovations to these 17 other wastewater pump stations listed in Appendix A to this order, and shall forever relinquish any and all claims for repair costs, renovation costs, and maintenance costs now or incurred in the future for these 17 wastewater pump stations and any other wastewater pump stations connected to the KDHWWTP wastewater collection system, or that WVO, the Associations, and/or any other KDHWWTP wastewater customers are responsible for the costs of the operation, maintenance, repair, renovation, and/or replacement and/or ownership of these 17 wastewater pump stations and any other wastewater pump stations connected to the KDHWWTP wastewater collection system.

36. Ordering paragraph 1 of the May 2011 Order required KDH to fully comply with all provisions in Finding of Fact 10.

37. The May 2011 Order required KDH to relinquish claims that customers were responsible for costs.

38. The May 2011 Order allowed KDH to incorporate these costs into its rate base in future proceedings before the Commission.

39. The Dare Centre Pump Station was the second worst of the 17 "orphan" pump stations at issue in the May 2011 Order.

40. However, before requiring KDH to assume this responsibility for replacement, the Presiding Commissioner in the May 2011 Order required the owners or representatives of the time share units to deliver an easement agreement for access, repair, maintenance, operation, and replacement of the disputed pump station "to KDH in [a] form <u>acceptable to KDH</u>." Emphasis added. (May 2011 Order, p. 6).

41. In the May 2011 Order, the Presiding Commissioner, in response to the Settlement Agreement and the procedural motion, ordered KDH and the Outer Banks Beach Club Associations to prepare and execute by a date certain, an executed perpetual easement for access, repair, maintenance, operation, and replacement of the disputed pump station in that docket.

42. As a part of that Order, the Presiding Commissioner required KDH to undertake a program designed to ensure the ongoing operation and performance, at a satisfactory level, of all of the other "orphan" pump stations.

43. KDH sent a letter to the fee owners of the Dare Centre on May 18, 2011, of which CPG received a copy, in which KDH stated that it recently agreed to assume the full responsibility for operating, repairing, maintaining, and if necessary, replacing the pump station. KDH stated that this would occur at no cost to the landowners. In the letter, KDH requested the underlying landowner of the Shopping Centre land, to execute a simple, one-and-a-half page, quit claim bill of sale and easement agreement. This is the same agreement that was signed by all of the other "orphan" pump station customer representatives except the K-Mart and the Wright Brothers Memorial hotel pump station owners.

44. On April 16, 2013, counsel for KDH again sent a letter to the fee owners of the Dare Centre, in which he again stated that KDH had agreed to assume the full responsibility for operating, repairing, maintaining, and if necessary, replacing the pump station. Counsel reiterated that this would occur at no cost to the landowners. In the letter, Counsel explained that because of some confusion as to who owned the pump station, KDH was requesting that the underlying landowner of the Shopping Centre land, execute a simple, one-and-a-half page, quit claim bill of sale and easement agreement.

45. The underlying landowners did not respond to counsel's letter of April 16, 2013.

46. Bill Freed through the company he operates, Enviro-Tech, provides operating services to KDH in its Kill Devil Hills service area, and responds to service requests through the KDH telephone number.

47. CPG likewise entered into service agreements with Enviro-Tech to maintain and operate the Dare Centre Pump Station.

48. Fifteen of the 17 owners of "orphan" pump stations signed quit claim bills of sale and easements in form satisfactory to KDH.

49. KDH and K-Mart negotiated additional terms ultimately mutually agreeable to both.

50. The owner of the hotel in front of the Wright Brothers Memorial insisted on retaining ownership and operating responsibility for the pump station serving his premises.

51. In subsequent conversations with the underlying landowner of the property on which the Dare Centre Pump Station is located, KDH was told to "get lost" and that the underlying landowners weren't going to give KDH a quit claim bill of sale or an easement. T. Vol. II, p. 25.

52. After receiving the aforementioned response from the underlying landowners, KDH sought the assistance of the Complainant to secure a quit claim bill of sale and easement from the underlying landowners.

53. In its dealings with the Complainant, KDH again fully agreed to assume operating responsibility for the Dare Centre pump station, including all costs of maintenance, repair and operation, including replacement if necessary.

54. KDH notified the Complainant that it would assume full responsibility for the disputed pump station if Complainant would execute a simple, one-and-a-half page, quit claim bill of sale and easement agreement.

55. However, the Complainant was unwilling to sign the very simple quit claim bill of sale and easement agreement that almost all of the other "orphan" pump station customers or customer representatives were willing to sign.

56. According to the Complainant, it was unwilling to sign the simple quit claim bill of sale and easement because the documents did not protect the Dare Centre and the Complainant's obligations to its retail customers.

57. Because of this, Complainant requested that KDH agree to include certain language in the documents that would protect Complainant's and its retail customers' interests.

58. Complainant offered several alternatives to the simple quit claim bill of sale and easement agreement that KDH provided to them for signature.

59. KDH did not accept any of the alternatives offered by Complainant.

60. Additionally, as negotiations went on, KDH began to back away from its offer to assume for responsibility to repair and replace the Dare Centre Pump Station without costs to the Complainant and the underlying landowner.

61. CPG filed this Complaint with the Commission in response to KDH's insistence that Complainant assume financial responsibility for the repair/replacement of the Dare Centre Pump Station before KDH would assume ownership and control of the station.

62. On or about April 16, 2013, CPG received a letter from KDH in which KDH agreed that KDH was responsible for maintenance and repair of the pump station. KDH noted that the underlying landowner of the Shopping Center land would be required to execute a simple, one-and-a-half page, quit claim bill of sale and easement agreement.

63. Beginning on April 24, 2013, counsel for CPG sent proposed additions to KDH for inclusion in KDH's proposed quitclaim bill of sale and easement. Although the parties have attempted to negotiate the terms of a bill of sale and easement, they have been unsuccessful in doing so.

64. During the course of their negotiations, KDH began demanding that CPG bring the Dare Centre Pump Station into compliance with DENR regulations and pay for costs of repair and replacement of the pump station before KDH would execute the documents for the pump station. Also, during the course of their negotiations, CPG began to demand that KDH reimburse CPG for expenditures that it had made to ensure that the Dare Centre continue to function properly for the benefit of CPG's customers in the Dare Centre.

65. The Dare Centre Pump Station is in extremely poor condition and is in danger of failing. The Dare Centre pump station's exterior is crumbling, and its metal components are rusted.

66. The estimate for replacing the Dare Centre Pump Station is approximately $103,750, an amount marginally in excess of the estimate in 2011 of $100,000.

67. The Dare Centre Pump Station is in need of replacing in the immediate future.

68. It was and is prudent and reasonable for KDH to secure a quit claim bill of sale and easement from the Complainant and underlying landowner before making expenditures or repairs on the Dare Centre Pump Station.

69. KDH had fulfilled its responsibility with all of the "orphan" pump stations except two, one of which is the pump station serving the Dare Centre and the second is the pump station serving the Wright Brothers Memorial hotel whose owner refused to relinquish control to KDH.

JURISDICTION

KDH is a public utility operating under the laws of the State of North Carolina and subject to the jurisdiction of the North Carolina Utilities Commission. KDH is engaged in the business of providing wastewater utility service to the public in the North Carolina Outer Banks.

CPG is a limited liability company organized under the laws of Delaware, with its principal place of business in Indianapolis, Indiana. CPG is an affiliate of Simon Property Group, Inc., a commercial real estate company.

This matter is properly before the Commission.

ANALYSIS OF EVIDENCE AND CONCLUSIONS

CPG requests the Commission to require KDH to reimburse CPG for expenditures that it has made to Enviro-Tech to maintain and repair the Dare Centre Pump Station and to require KDH to accept a bill of sale and easement that CPG has drafted that provides language which better protects the rights of Complainant and its retail customers. Complainant claims it is entitled to such an order because, in 2001 and again in 2011, the Commission ordered KDH to take ownership and responsibility for its entire wastewater collection system and to relinquish claims for costs related to this action that it might have against its customers. After carefully considering the evidence presented in this proceedings and the record proper, the Commission determines that KDH is not required to reimburse CPG for any expenditures that CPG has made to ensure that the Dare Center Pump Station remains operative and that KDH is not required to accept the alternatives to the simple quit claim bill of sale and easement that CPG has offered in return for accepting financial responsibility for the pump station.

Four threshold facts underlie the Commission's determinations: (1) The Dare Centre Pump Station is an orphan pump station, i.e., a station whose ownership is unclear; (2) the underlying landowners are the record owners of the real property upon which the Dare Centre Pump Station is constructed; (3) according to the land registry of Dare County, KDH is not the record owner of the land upon which the Dare Centre Pump Station is constructed; and (4) KDH does not have an easement over any land allowing it to provide service to the Dare Centre Pump Station.

Both Complainant and Respondent submitted substantial evidence in support of their contentions that the other owns the Dare Centre pump station and bears responsibility for improvements. This evidence took the form of reliance on the party in whose name environmental permits have been issued, conduct with respect to repair and maintenance, alteration of piping configuration, etc. However, neither party presented evidence tending to show title or ownership in the pump station in the form of chain of title or evidence showing who initially paid for and installed the pump station. To the extent it was OBBCI, as both parties are successors in interest, it is unclear which party succeeded to ownership in the pump station. Such evidence would have been useful to the Commission in placing responsibility in this docket with Complainant or Respondent, but it is not in the record. The absence of such evidence in the prior proceedings formed the basis for the relief the Commission authorized which included in part that KDH obtain transfers of ownership interests from other potential claimants before KDH embarked upon making improvements, the cost of which ultimately was to be borne by the general body of KDH's ratepayers. This deficiency still exists, and the Commission declines to make KDH responsible for costs where other potential ownership claimants refused to execute the requested documents.

On at least two occasions, this Commission has directed KDH to acquire ownership and control of its entire collection system which includes the Dare Centre Pump Station. KDH has made repeated attempts to comply and to persuade Stella Land and Complainant to convey this ownership interest.

Although KDH has not succeeded in obtaining compliance in the case of the Dare Centre station, KDH sent a letter to each of the orphan pump station owners seeking to acquire ownership of the orphan pump stations as required by the Commission's 2001 Order in 2004. KDH again sent a letter to the underlying landowners of the Dare Centre Pump Station seeking to acquire ownership of the station shortly after the May 2011 Order was issued. The underlying landowners did not answer KDH's first letter and allowed the second letter to be returned with an indication that the addressee did not reside at the address even though it was the same address as the address provided in the tax records. The first letter was sent within 10 days after the May 2011 Order was issued and the second letter was sent approximately a year later. After the second letter was returned, KDH contacted the Complainant, the underlying landowners' primary tenant, in hopes that the Complainant could assist KDH in securing ownership of the pump station. Despite Complainant's assistance, KDH and the underlying landowners have been unable to reach an agreement that would result in the transfer of the underlying landowners' interest in the Dare Centre Pump Station to KDH. Consequently, KDH did not have either clear, undisputed ownership in and to this pump station or a recorded legal easement access to it as contemplated by the Commission in its orders. As a result, KDH has justifiably refused to expend funds to repair the pump station and has refused to reimburse the Complainant for any expenditure that Complainant has made to keep the station in working order since the issuance of the May 2011 Order.

While the Complainant acknowledges the efforts made by KDH to secure an ownership interest and that those efforts have been successful in resolving the ownership issues regarding 16 of the 17 orphan pump stations, in the Complainant's opinion, KDH's refusal to expend funds to repair the station and to reimburse Complainant for the funds that it has expended to repair the station violates the May 2011 Order because: (1) the Order expressly <u>requires</u> KDH to assume responsibility for all costs incurred to repair or replace the Dare Centre Pump Station; and (2) the Order <u>does not explicitly</u> require the owner of the Dare Centre Pump Station to transfer any interest in that pump station to KDH to be relieved of financial responsibility for the orphan pump station. Complainant thus asserts that, under the literal terms of the May 2011 Order, KDH is financially responsible for the repair or replacement of the Dare Centre Pump Station even if another party such as the underlying landowners remain the legal, record owners of the property. According to Complainant, this is true even if, as the facts of this case illustrate, the underlying landowner refuses to respond to KDH's offer to assume total responsibility for an ailing Dare Centre Pump Station in exchange for a quit claim bill of sale and easement that transfers only the interest that the underlying landowners have in the structure.

The Commission does not agree with the Complainant's interpretation of the May 2011 Order because it ignores the context and the practical implications of Commission's order and the prior directives to KDH. In addition, it permits Complainant and those in financial interest with it to benefit, at the expense of KDH and its ratepayers, from their own intransigence. More precisely, Complainant's interpretation is inconsistent with Ordering Paragraphs 8 and 9 of the 2001 Order which stated:

> 8. That KDHWWTP, LLC, shall address DWQ noncompliance and bring its facilities into full compliance with DWQ regulations within 18 months after the transfer.
>
> 9. That KDHWWTP, LLC, <u>shall acquire ownership of the entire collection system infrastructure</u> within 12 months. (Emphasis added).

This interpretation is also inconsistent with CPG's foundational argument set forth in its brief and proposed order that:

> Both the October 31, 2001 Order and the May 10, 2011 Order require KDHWWTP <u>to acquire ownership of its entire wastewater collection system</u> and relinquish all claims for costs, including specifically that any KDHWWTP wastewater customers are responsible for costs. (Emphasis added.)

CPG's Proposed Order, p. 15.

The core of the Commission's original directive in 2001 and continuing directive in 2011 is that KDH should acquire ownership of its entire wastewater system. Complainant's interpretation, which requires KDH to make substantial expenditures to a facility, the ownership of which is unclear, does nothing to further the Commission's stated goal that KDH become the undisputed owner of its wastewater system. To the contrary, the Complainant's interpretation further perpetuates the ineffectual and dysfunctional predicament that existed prior to the May 10, 2011 Order where no clear ownership lines were drawn for assets that ultimately assisted the utility in providing wastewater utility services. Moreover, the Complainant's interpretation flies in the face of the direct action that the Commission took to address the only orphan pump station that was of immediate concern in the 2010-2011 investigation, i.e. the Disputed Pump Station.

The May 2011 Order was issued as a result of an agreement between the record parties in the dispute. The order accepts the settlement agreement and attempts to effectuate it. Thus, the intent of the parties must be factored into any interpretation of the Order. In the stipulation and the Joint Proposed Order, the stipulating parties of record indicated that the owner of the disputed pump station that gave rise to the initial investigation agreed "to deliver in [a] form acceptable to KDH and recordable in the Dare County Register of Deeds, an executed perpetual easement for access, repair, maintenance, operation, and replacement of the Disputed Pump station in accordance with a North Carolina General Utility easement." May 2011 Order, p. 6.

By this language, the stipulating parties indicated that a fundamental purpose of this investigation was to clearly and legally establish KDH's ownership of the disputed OBBC pump station once and for all. Given this language and the actions taken by the parties of record to implement the agreement, it is clear the parties intended to impose a similar responsibility on any other potential owner of a disputed pump station such as Stella Land or CPG that attempts to rely upon the substance of the agreement in an entirely different proceeding.[1]

Furthermore, the issue of ownership or control of orphan pump stations was at the heart of the dispute in Docket No. W-1160, Sub 10. As has been duly noted, that docket ultimately was resolved by a stipulation approved by the Presiding Commissioner. An antecedent to the stipulation was a Joint Motion to Hold Matter in Abeyance on behalf of the Public Staff and KDH dated February 23, 2011. In paragraph 5(b) of the Motion, the following appears:

> Finally KDH will require, as a condition for making any improvements, repairs and/or replacements, that the property owners on whose property the affected pump station is located execute a Bill of Sale and Easement Agreement with KDH.

Appendix A to the Motion encaptioned "Bullet Point Proposal of KDHWWTP," similarly states:

> KDHWWTP will obtain a Bill of Sale and Easement Agreement from the property owners/customers prior to replacing or repairing the pump stations and will request DWQ to issue permits in its name.

This requirement was at least implicitly incorporated into the May 2011 Order which approved the stipulation.

Complainant relies heavily on the terms of the Commission order in Docket No. W-1160, Sub 10 as support of the relief it requests. However, from the Commission's review, an important consideration in the requirement that KDH obtain ownership and control of orphan pump stations and thereafter bear sole responsibility for operating and maintaining them was that KDH first obtain unencumbered ownership through a quit claim bill of sale and easement. In compliance with this consideration, within a reasonable time after entry of the order, KDH sought a quit claim bill of sale and easement in form satisfactory to KDH from those according to the Register of Deeds of Dare County who owned the property on which the pump stations were located. With limited exception, in particular the owner of the Dare Centre pump station at issue in this docket, the owners complied, KDH obtained DWQ permits and assumed ownership, operation, and control.

A reasonable assumption underlying the terms of the May 2011 Order and the settlement upon which it was based was that those with a colorable ownership interests in the orphan pump stations would view such ownership as a liability, not an asset, and would willingly execute the quit claim bill of sale and easement to avoid responsibility for the pump stations and place the responsibility with KDH to ensure that thenceforth the pump stations would be used for their

[1] The Commission finds that it is particularly telling that the Complainant did not present evidence from the Public Staff or any of the other participants in Docket W-1160, Sub 10 that the parties intended for KDH to expend funds to repair and/or replace these orphan pump stations without clarifying the questions surrounding the ownership of these stations through the use of a quit claim bill of sale and easement. From this omission and the actions of KDH shortly after the issuance of the May 2011 Order, the Commission concludes that the parties intended for KDH to impose the same or similar conditions for the receipt of funds on the alleged owners of any of the remaining pump stations that it imposed on the Outer Banks Beach Club Associations.

intended purpose. Such was the relief sought against KDH, the relief KDH originally resisted, but the relief to which KDH agreed and the Commission required. The requirements in the Commission's order were not intended to place Complainant in a favorable bargaining position so as to dictate bill of sale and easement terms favorable to Complainant.

KDH sought a quit claim bill of sale and easement in form satisfactory to KDH from Stella Land and Development Corporation, the owner of the land on which the Dare Center pump station is located. Stella Land and Development Corporation was and now is the landlord of Complainant and obviously benefits from rents Complainant pays. Stella Land declined to execute the tendered documents. Complainant, a sophisticated business entity with access to competent and capable legal representation, knew or should have known the terms of the Commission's requirements in its order in Docket No. W-1160, Sub 10 and knew or should have known that the impediment preventing the takeover of control of the Dare Center pump station was the failure of its landlord to respond to KDH's timely request. While Complainant may have misunderstood facts including the relationship between Respondent and Mr. Freed and his organization, Enviro-Tech, the Commission determines that Complainant has failed to meet its burden of proof to support allegations that Respondent sought willfully to misrepresent facts or to deceive Complainant. The Commission rejects Complainant's allegations that it bore no responsibility to apprise itself of the facts, utilize its leverage as tenant of Stella Land Development Corporation to influence Stella timely to respond or that Respondent "hoodwinked" Complainant into any misunderstanding of the facts that a reasonable investigation would have revealed. Thus, the Commission rejects any suggestion by Complainant that questions regarding KDH's ownership interest did not have to be resolved before KDH would be required to expend funds to repair and/or replace the Dare Centre Pump Station.

Having decided that KDH was not required to expend any funds to repair a pump station that it did not own or whose ownership remained clouded, the Commission determines that KDH should not be responsible to reimburse CPG for expenditures that it has made for the repair of the Dare Centre Pump Station since the entry of the May 2011 Order.

In its Brief, the Complainant argues that KDH is required to reimburse the Complainant for these expenditures because KDH is collaterally estopped from denying that KDH is responsible for the repair and/or replacement expenditures that arose at the Dare Centre Pump Station from the date that the May 2011 Order was issued. Collateral estoppel applies when: (1) a prior proceeding resulted in a final judgment on the merits, (2) identical issues were involved, (3) the issue was actually litigated and necessary to the judgment, and (4) the issue was actually determined. McDonald v. Skeen, 152 N.C. App. 228, 230, 567 S.E.2d 209, 211, *disc. review denied,* 356 N.C. 437, 571 S.E.2d 222 (2002) (citing Thomas M Mcinnis & Assoc., Inc. v. Hall, 318 N.C. 421, 429-30, 349 S.E.2d 552, 557-58 (1986)).

As discussed at length in this Order, the Commission determines that it is Complainant that has inappropriately interpreted the Commission's May 2011 Order in Docket No. W-1160, Sub 10 not the Respondent. Were the Commission to apply the doctrine of collateral estopped, it would therefore be Complainant's contentions that would be in jeopardy, not Respondent's. Complainant is complicit in actions that prevented Respondent from acquiring the ownership interest the Commission concluded would have been forthcoming as a precondition to Respondent's expenditures of funds on the pump stations. As such, Complainant is in no position to assert collateral estopped to require reimbursement.

Review of the record in Docket No. W-1160, Sub 10 indicates that the Commission assigned the investigation requested by the Public Staff in that docket to a panel of three commissioners. The matter was scheduled to be heard by the panel on May 11, 2011. However, prior to the matter being heard, the parties filed a joint motion requesting that the evidentiary hearing be postponed because they had reached a joint agreement to resolve the issues in the docket. The parties attached a Proposed Order that memorialized the extent of their agreement. According to the draft order and the agreement of the parties, the draft order was to be issued by the Presiding Commissioner. As such, the May 2011 Order is not a "final order" on the merits sufficient to form the basis of collateral estopped defense.

The Commission concludes that it would not be reasonable, prudent or in the public interest to hold KDH responsible for the repair and replacement cost of the Dare Centre Pump Station from the date of that Order <u>and</u> to thereafter require KDH to reimburse CPG for funds that CPG expended to repair the Dare Centre Pump Station. For the Commission to decide otherwise, it would have to conclude that KDH has acted unreasonably and unfairly in its dealings with CPG and that KDH has improperly charged CPG for the repairs made to the Dare Centre Pump Station.

All parties agree that the pump station is failing and in need of immediate repair. Despite this knowledge, it appears that the parties' negotiations are still at an impasse as to the terms of any quit claim bill of sale and an easement. CPG has asked that the Commission order KDH to accept the modified bill of sale and easement that it has submitted during this proceeding.

The Commission declines to impose upon KDH easement terms it is unwilling to accept. In the Commission's opinion, disputes over the terms of easements are best left to the grantor and grantee to resolve through arms' length and good faith negotiations.

If Complainant and KDH can come to terms on the language of a bill of sale and easement, either mutually agreeable to both or, alternatively, no more onerous to Complainant or favorable to Respondent than that tendered to Stella Land in 2011, the Commission determines that Respondent shall take over ownership and control of the pump station as originally contemplated in Docket No. W-1160, Sub 10. Ownership and control with KDH best serves the public interest and is consistent with the prior resolution of issues in dispute over the wastewater system. The Commission determines that should KDH obtain ownership of the Dare Centre Pump Station, it likewise should receive ownership and responsibility for the collection sewer piping beyond the meters of the consumers in the Dare Centre and the pump station. The Commission determines that these facilities are integral parts of the collection and treatment system and transfer of ownership and control to KDH best serves the public interest. However, Respondent's financial responsibility for any pump station upgrade and repair at the time of acquisition shall be limited to $100,000, the estimated cost KDH would have incurred had Stella timely responded to KDH's offer. As previously determined in the May 2011 Order, KDH will be authorized to recover such expenditures through base rates. To the extent such costs exceed $100,000, Complainant shall be responsible therefor. If Complainant refuses to undertake this obligation, Respondent is relieved of its obligations imposed in the Commission's May 2011 Order and Complainant and/or Stella

Land can retain control and operation of the Dare Centre Pump Station as has one other orphan pump station owner who likewise wished to retain ownership.

The Dare Centre Pump Station, in whomsoever its ownership rests, has been and is used to provide wastewater utility service to the public for compensation, specifically the tenants of Complainant in the Dare Centre. As such, the owner, whosoever that shall be, is a public utility, either de jure or de facto, and subject to the Commission's regulation.[1] Without question, KDH pursuant to statute falls within the Commission's jurisdiction. As such, to the extent disputes arise over access to or interference with Dare Centre operations, the Commission provides a forum within which to address and resolve them. Where such disputes arise the Commission seeks to balance the interests of property owners to avoid undue interference and the interests of the utility to provide adequate service at reasonable costs.

Finally, the Commission acknowledges that Respondent asserts that it has unnecessarily expended substantial resources in defending this action which, according to Respondent, is in large measure without merit and that the parties would have been better served by using the resources expended in litigating this matter in up fitting the pump station. The Commission finds merit in this contention. The Commission determines that Respondent should make an accounting of its costs expended to defend this docket. The Commission determines that it will examine the costs and, if it determines them to be reasonable and prudent, will permit Respondent to place such costs in a deferred account for consideration for recovery in Respondent's next rate case. At that time the Commission will address disposition of such funds including from whom they may be recovered.

CONCLUSIONS

After carefully considering the evidence in this docket, the record proper and taking judicial notice of the Commission's records as cited herein, the Commission concludes as follows:

1. It was and is prudent and reasonable for KDH to secure a quit claim bill of sale and easement from Complainant and underlying landowner before making expenditures for or repairs on the Dare Centre Pump Station.

2. KDH did not violate the terms and conditions of the May 2011 Order.

3. KDH is not required to reimburse CPG for any expenditures that CPG has made to Enviro-Tech to ensure the continued operation of the Dare Centre Pump Station since the entry of the May 2011 Order.

4. KDH should make an accounting of its costs expended to defend this docket. If, after a thorough examination, the Commission determines the costs to be reasonable and prudent,

[1] State ex rel. Utilities Com'n v. Buck Island, Inc., 162 N.C. App. 568, 592 S.E.2d 244 (2004). State ex rel. Utilities Comm. v. Mackie, 79 N.C.App. 19, 26, 338 S.E.2d 888, 893-894 (1986), modified, 318 N.C. 686, 351 S.E.2d 289 (1987).

KDH shall be allowed to place such costs in a deferred account for consideration for recovery in Respondent's next rate case.

5. It is in the parties' interest for this situation to once and for all be resolved. If no agreement can be reached, KDH will be released from its responsibilities under the Commission's order in Docket No. W-1160, Sub 10 and Complainant and/or Stella Land can retain control and operation of the Dare Centre Pump Station as has one other orphan pump station owner who likewise wished to retain ownership.

6. The parties shall submit a written report to the Commission within 30 days informing the Commission as to how the provisions of this order are to be implemented.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _7th__ day of August, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semi-Annual Adjustments to Water and Sewer System Improvement Charges pursuant to G.S. 62-133.12	)	ORDER APPROVING WATER AND SEWER SYSTEM IMPROVEMENT CHARGES ON A PROVISIONAL BASIS AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On October 31, 2014, Aqua North Carolina, Inc. (Aqua), filed an application requesting authority to impose water system improvement charges (WSIC) and sewer system improvement charges (SSIC) effective January 1, 2015, pursuant to Commission Rules R7-39 and R10-26 (Application). On November 21, 2014, Aqua filed an amendment to the Application.

On November 26, 2014, the Public Staff filed Notice of the Public Staff's Plan to Present Recommendations regarding the proposed WSIC and SSIC at the Commission's December 15, 2014 Regular Staff Conference.

On December 9, 2014, the Public Staff filed a report and recommendations concerning Aqua's proposed WSIC and SSIC.

On December 15, 2014, the Attorney General, acting pursuant to G.S. 62-20, made a Filing in Opposition to SIC Proceeding and Rate Increase. Having appealed the Commission's prior decision approving the rate adjustment mechanisms, the Attorney General stated that he "intends to appeal if an order is issued [in this case] that allows a rate increase pursuant to the … mechanism," and "requests that Aqua be required to maintain detailed records that would help facilitate potential refunds should the Commission's determination allowing the … mechanism and procedure be reversed on appeal."

On December 15, 2014, the Public Staff presented this matter to the Commission at the Regular Staff Conference. During Staff Conference, the Attorney General expressed opposition to the recommendations made by the Public Staff and Aqua and responded to questions from the Commission. Aqua also made a presentation and responded to questions raised by the Commission. In response to an inquiry by the Chairman as to whether any member of the public wished to be heard on the proposals made by Aqua and/or the recommendations made by the Public Staff, no public witnesses requested to testify.

On the basis of the verified Application, the records of the Commission, and the comments and presentations of the Public Staff, the Attorney General, and Aqua, the Commission makes the following

FINDINGS OF FACT

1. Aqua is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Aqua is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. In Aqua's last general rate case, Docket No. W-218, Sub 363 (Sub 363 Rate Case), the Commission approved in its Order dated May 2, 2014, Aqua's request to utilize a WSIC and SSIC pursuant to G.S. 62-133.12, concluding that the rate adjustment mechanisms are in the public interest and establishing WSIC and SSIC procedures for Aqua.

3. Aqua's WSIC and SSIC procedures allow for semi-annual adjustments to Aqua's rates every January 1st and July 1st based upon reasonable and prudently incurred investment in eligible system improvements completed and placed into service prior to the filing of the request. Eligible system improvements are water and sewer system improvements set forth in G.S. 62-133.12(c) and shall include only those improvements found necessary by the Commission to provide safe, reliable, and efficient service in accordance with applicable water quality and effluent standards.

4. This is Aqua's first filing to implement charges under the WSIC and SSIC mechanisms. Due to the timing of the order issued in the Sub 363 Rate Case, Aqua's request includes WSIC and SSIC projects completed and placed into service from December 1, 2013, through September 30, 2014, which consist of the following:

Replace meters and meter boxes	$242,994
Replace services	277,046
Replace hydrants	4,122
Install filter for radium removal at Triple Lakes	93,769
Install filter for nitrate removal at Mountain Creek	68,338
Install filter for VOC removal at Tyler Farms	63,876
Main relocations	90,847
Total WSIC plant additions	$840,992
Replace grinder pumps	$144,339
Replace lift station and treatment plant pumps	198,460
Replace blowers and motors	24,404
Inflow & infiltration improvements	12,239
Total SSIC plant additions	$379,442

5. Under G.S. 62-133.12(c), eligible water system improvements include equipment and infrastructure approved by the Commission to be installed to comply with secondary drinking water standards. There are no improvements to address secondary drinking water standards included in the Company's request.

6. Aqua's proposed WSIC and SSIC percentages to be implemented on January 1, 2015, are as follows:

	Proposed WSIC/SSIC Revenue Requirement	Projected Service Revenues	WSIC/SSIC Percentage
Aqua water	$66,146	$31,650,370	0.21%
Aqua sewer	50,967	11,556,231	0.44%
Fairways water	63	877,033	0.01%
Fairways sewer	2,232	1,171,537	0.19%
Brookwood water	41,734	4,976,203	0.84%

7. Pursuant to G.S. 62-133.12(g), the cumulative WSIC & SSIC percentages are capped at 5% of the total annual service revenues approved by the Commission in the Sub 363 Rate Case, resulting in the following maximum revenue requirements for Aqua's WSIC & SSIC:

	Sub 363 Rate Case Annual Service Revenues	Proposed WSIC/SSIC Revenue Requirement	Maximum WSIC/SSIC Revenue Requirement
Aqua water	$31,160,353	$66,146	$1,558,018
Aqua sewer	10,887,285	50,967	544,364
Fairways water	874,636	63	43,732
Fairways sewer	1,135,185	2,232	56,759
Brookwood water	4,981,656	41,734	249,083

8. Aqua's proposed WSIC and SSIC revenue requirements do not exceed the maximum WSIC and SSIC revenue requirements.

9. As stated by the Commission in the order adopting Rules R7-39 and R10-26 issued on June 6, 2014, in Docket No. W-100, Sub 54, the Public Staff is to review all infrastructure improvements proposed for recovery for eligibility and reasonableness prior to making its recommendation to the Commission on WSIC or SSIC rate adjustments. Furthermore, any WSIC or SSIC rate adjustments will be allowed to become effective, but not unconditionally approved. The adjustments shall be further examined for a determination of their justness and reasonableness in the Company's next general rate case. At that time, the adjustments may be rescinded retroactively if the Commission determines that the adjustments were not prudent, just and/or reasonable.

10. The Public Staff has carefully reviewed the WSIC and SSIC infrastructure improvements. The Public Staff sent Aqua a total of 19 Data Requests, with a total of 182 items. Aqua responded fully to each of the Data Requests.

11. The Public Staff recommended seven adjustments to Aqua's proposals. Aqua does not oppose the following five adjustments:

a. Correct Fairways Water Amounts.
b. Reflect Average Balances for 2015 – While Aqua does not oppose this adjustment at this time, Aqua reserved the right to contest this adjustment in the future.
c. Correct Error in Aqua Sewer Operations Amounts.
d. Remove Non-Eligible Services and Meters.
e. Remove Non-Eligible Meter Boxes and Appurtenances.

12. Aqua does not agree with the Public Staff's two adjustments concerning the cost of radio frequency (RF) ready meters and removal of the deferred tax asset.

13. The record is insufficient for the Commission to determine whether the replacement of traditional water meters with RF-ready meters is an in-kind replacement under G.S. 62-133.12(c)(1) and/or whether such replacement is reasonable, prudent and cost-effective.

14. The record is sufficient to support an adjustment to allow recovery for installed replacement RF-ready meters at an amount equal to the cost of traditional meters. This adjustment is provisional in nature and subject to review for justness and reasonableness in Aqua's next general rate case.

15. The record is insufficient for the Commission to determine that the deferred tax assets are properly included by Aqua in its calculation of the WSIC and SSIC revenue requirements.

16. The record is sufficient to support the removal of the deferred tax asset and to adjust the rate accordingly as proposed by the Public Staff.

17. Based on the Public Staff's investigation to date, all the water system improvement projects the Public Staff recommended for approval are eligible water system improvements as defined in G.S. 62-133.12(b) and (c). The Public Staff will continue to review the justness, prudency, and reasonableness of these improvements during its review in Aqua's next general rate case.

18. Based on the Public Staff's investigation to date, all the sewer system improvement projects the Public Staff recommended for approval are SSIC eligible sewer system improvements as specified in G.S. 62-133.12(b) and (d). The Public Staff will continue to review the justness, prudency, and reasonableness of these improvements during its review in Aqua's next general rate case.

19. Based on the seven Public Staff adjustments, the Public Staff recommended the following adjustments to the WSIC and SSIC percentages proposed by Aqua and the following WSIC and SSIC revenue requirements:

	WSIC/SSIC Percentages Per Aqua	WSIC/SSIC Revenue Requirement Per Public Staff	Impact of Public Staff Adjustments	WSIC/SSIC Percentage per Public Staff
Uniform water	0.21%	$44,192	-0.07%	0.14%
Uniform sewer	0.44%	36,476	-0.12%	0.32%
Fairways water	0.01%	11	-0.01%	0.00%
Fairways sewer	0.19%	1,588	-0.05%	0.14%
Brookwood water	0.84%	20,585	-0.43%	0.41%

DISCUSSION

In this proceeding, the Public Staff recommended five adjustments which Aqua did not oppose. Although the Attorney General objects in principle to the adoption and implementation of a system improvement charge, he has not filed any specific objections as to the recommendations of Aqua and the Public Staff. Therefore, the five unopposed adjustments are adopted for the reasons suggested by the Public Staff.

The Public Staff also proposed two additional adjustments concerning the cost of radio frequency (RF) ready meters and removal of the deferred tax asset. Aqua and the Public Staff do not agree on these adjustments. They do, however, agree that the record as it currently exists is insufficient to definitively resolve the RF-ready meter issue and the deferred tax issue and proposed that the Commission schedule an evidentiary hearing to resolve these issues. The Public Staff and Aqua, therefore, urge the Commission: (1) to provisionally accept the recommendations made by the Public Staff and impose a WSIC and SSIC based on the Public Staff recommendations, and (2) to schedule and hold an evidentiary hearing in which discovery is undertaken and testimony is pre-filed so that a final decision can be reached on these issues.

The Commission notes that this is the first proceeding in which a utility has requested that the Commission allow it to impose a system improvement charge. The process adopted for consideration of WSIC and SSIC proposals is far different than the procedures that ordinarily are followed when a water or sewer utility seeks to recover in a general rate case for the investments that it has made to improve its systems. The procedures that were adopted both in the Sub 363 Rate Case and in the Commission's rulemaking proceeding were truncated and streamlined so that a utility could pursue recovery of its investments made between rate cases and that the Commission could determine the merits of the requests in an expedited manner. The Commission adopted these streamlined and truncated procedures at the urging of, and with the agreement of, the two major water utilities in this state, Aqua and Utilities, Inc., and the Public Staff. Because these procedures were streamlined to expedite consideration of the expenditures on an accelerated timetable, there are certain limitations inherent in these procedures. One such limitation is that the procedures adopted do not contemplate the use of evidentiary hearings to resolve disputes between the utility and other parties in system improvement charge proceedings. Although the Commission has inherent authority to schedule an evidentiary hearing to consider a proposed system improvement charge, should the need arise, the Commission intends to exercise this discretion rarely so as to not undercut the foundation upon which the system improvement charge rules are based. Rather, the Commission expects the parties to provide sufficient information in their filings to allow the Commission to render a decision with regard to the proposed surcharge without resort to an evidentiary hearing outside of a general rate case proceeding.

After careful consideration, the Commission concludes that the proposed WSIC and SSIC, as adjusted by the Public Staff, should be allowed to become effective for service rendered on and after January 1, 2015, on a provisional basis subject to further review in Aqua's next general rate case, as recommended by the Public Staff. The Commission further concludes, however, that the information provided in the record in this proceeding is insufficient for the Commission to decide the outstanding issues in the case regarding the RF-ready meters and the deferred tax asset. For example, with regard to the RF-ready meters, the Public Staff stated that Aqua has not provided sufficient information on cost-effectiveness to justify their installation. As the Public Staff stated, the same RF meter issue that is the subject of dispute in this proceeding was a subject of intense dispute in the Sub 363 Rate Case. In that docket, the Public Staff and Aqua could have availed themselves of discovery, pre-filed testimony, direct and cross examination of witnesses and all the other tools that would have allowed this matter to have been finally decided by the Commission. Rather than availing themselves of these tools, Aqua and the Public Staff entered into a stipulated agreement in which the Public Staff and Aqua agreed that there would be no final resolution of this issue and that the Public Staff could challenge the reasonableness, prudency and cost effectiveness of the RF meters in future cases. See Paragraph 15 of Stipulation in the Sub 363 Rate Case. As a result, the record in this proceeding is devoid of useful information from that proceeding upon which the Commission could rely upon in this proceeding to make a reasoned decision on this issue. Instead, the Commission is left with a challenge by the Public Staff as to the prudence, reasonableness and cost-effectiveness of Aqua's plan to install approximately $21.8 to $25.4 million as an investment in RF meters to serve existing customers. Similarly, as the parties acknowledged in proposing an evidentiary hearing, the information in the record regarding the Company's net operating loss is inadequate for the Commission to decide the issue regarding the deferred tax asset. This does not, however, foreclose the Company's opportunity to have these issues considered in future WSIC proceedings in which additional information is provided to justify the inclusion of such costs. The Company, in future filings, should take care to ensure that its requests are well-considered, justified, and fully supported by clear, complete information sufficient to permit the Commission to act thereon. Likewise, after its review and audit of the Company's filing, to the extent the Public Staff takes issue with the Company's request, its submissions to the Commission should be well-considered, justified, and fully supported by clear, complete information sufficient to permit the Commission to act thereon. To the extent the parties' information permits the Commission to rule on a provisional basis without a further evidentiary hearing, it will do so. Otherwise, the Commission will determine whether to conduct a hearing or to again defer its decision to the next general rate case.

The Commission, therefore, will approve and allow the recommended WSIC and SSIC, as adjusted by the Public Staff, to become effective on a provisional basis. Allowing the WSIC and SSIC to become effective on a provisional basis does not prevent any party from challenging the Commission's decision in subsequent proceedings or a general rate case, nor does it preclude the Commission from finding in a subsequent proceeding that the expenditures in question were not prudent or reasonable and retroactively requiring that the amounts collected be refunded with interest. The Company shall maintain all necessary records to allow such refunds, if necessary, to be determined.

Finally, both the Alternative Procedures approved in the Sub 363 Rate Case and the Commission's system improvement charge rules adopted specific procedures to initiate WISC and SSIC adjustments. Both require the Public Staff to "schedule the request for Commission consideration at the regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed … charge. The Public Staff shall formally notify the Commission at least 15 days in advance of the date that the request shall be scheduled for Commission consideration at the regularly scheduled staff conference." See Rules R7-39(f) and R10-26(f). When adopting these procedures and the subsequent rules, the Commission intended for these procedures and Rules to provide additional notice to Aqua's customers and the public of the proposed surcharges and to supersede the normal practice of the Public Staff and the Commission, which permits agenda items for the regular staff conference held on Mondays of each week to be filed with the Commission on or before the previous Wednesday. In adopting Rules R7-39(f) and R10-26(f), the Commission intended that the Public Staff file the substance of its comments and recommendations at least 15 days in advance of the scheduled hearings so that the public could be adequately informed as to issues in the requests and to make decisions as to their participation based upon this information. Such advanced notice is important because of the streamlined and expedited nature of these proceedings. Although the rules could be read simply to require notice of the date on which such items would be presented to the Commission at its regular staff conference, as was provided by the Public Staff in this instance, the Commission hereby clarifies the intent of these rules and directs the Public Staff to file the substance of its comments and recommendations regarding a request by a public utility to impose a surcharge pursuant to Rules R7-39 and R10-26 at least 15 days in advance of the regular staff conference in which those issues are to be considered.

CONCLUSION

Based upon the foregoing, the Commission concludes that Aqua should be allowed to implement the WSIC and SSIC rate adjustments recommended by the Public Staff effective for service rendered on and after January 1, 2015. The WSIC and SSIC rate adjustments, while allowed to become effective, are not unconditionally approved, and will be subject to further examination for justness and reasonableness in Aqua's next general rate case. Further, the Commission directs the Public Staff to file the substance of its comments and recommendations regarding a request by a public utility to impose a system improvement charge at least 15 days in advance of the regular staff conference in which the charge is to be considered.

IT IS, THEREFORE, ORDERED as follows:

1. That Aqua is authorized to implement the proposed Water and Sewer System Improvement Charges set forth in the attached Appendix A-3 to Aqua's Schedule of Rates effective for service rendered on and after January 1, 2015. The rates contained therein are provisional and subject to review in Aqua's next general rate case.

2. That the attached Appendix A-3 is approved and is deemed filed with the Commission pursuant to G.S. 62-138.

3. That Aqua shall mail to each of its customers with the next regularly scheduled customer billing the Commission approved customer notice.[1]

4. That, in the future, the Public Staff shall file the substance of its comments and recommendations regarding a request by a public utility to impose a system improvement charge at least 15 days in advance of the regular staff conference at which the charge is to be considered.

ISSUED BY ORDER OF THE COMMISSION.
This the _22nd_ day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A-3

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All Aqua NC water systems except as noted below	0.14% 1/
Water systems in Brookwood and LaGrange service areas	0.41% 1/
Water systems in Fairways and Beau Rivage service areas	0.00% 1/
Glennburn, Knollwood, and Wimbledon systems in Gaston County	None 2/

SEWER SYSTEM IMPROVEMENT CHARGE

All Aqua NC sewer systems except as noted below	0.32% 3/
Sewer systems in Fairways and Beau Rivage service areas	0.14% 3/

1/ The Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

2/ These water systems, which were acquired from Wayne M. Honeycutt in Docket No. W-218, Sub 385, are not included under Aqua's uniform rates and improvements made in these systems are not eligible for Water System Improvement Charge recovery.

3/ The Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

[1] Three separate customer notices are attached hereto as Attachments A, B and C, respectively. The separate customer notices are intended to minimize customer confusion. Aqua shall mail the appropriate customer notice to each of its customers with the next regular customer billing.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 363A on this the __22nd__ day of __December ___, 2014.

ATTACHMENT A
Page 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North	)	NOTICE TO CUSTOMERS IN
Carolina 27511, for Approval of Semi-	)	BROOKWOOD/LAGRANGE
Annual Adjustments to Water and Sewer	)	SERVICE AREAS
System Improvement Charges Pursuant to	)	
G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 22, 2014, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua NC), to implement a Water System Improvement Charge (WSIC) for service rendered on and after January 1, 2015, in Aqua NC's Brookwood/LaGrange service areas in Cumberland and Hoke Counties, in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua NC's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua NC's last general rate case.

Commission Rules R7-39(h) and R10-26(h) specify that the WSIC and SSIC shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

The Public Staff carefully reviewed Aqua NC's stated WSIC and SSIC improvements, including a detailed review of invoices, materials lists, work orders, employee time sheets, and other accounting records, and filed a Report with recommendations on December 9, 2014.

The following are the WSIC charges Aqua NC applied for in its October 31, 2014 Application for the Brookwood and LaGrange service areas, the amount recommended by the Public Staff, and the Commission approved WSIC:

ATTACHMENT A
Page 2 of 2

	Aqua NC Applied for	Public Staff Recommendation	**Commission Approved**
WSIC	0.84%	0.41%	**0.41%**

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 31, 2014, the December 9, 2014 Public Staff Report, and the December 22, 2014 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e. for Docket No. key: W-218 Sub 363A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

ATTACHMENT B
Page 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North	)	NOTICE TO CUSTOMERS IN
Carolina 27511, for Approval of Semi-	)	FAIRWAYS AND BEAU RIVAGE
Annual Adjustments to Water and Sewer	)	SERVICE AREAS
System Improvement Charges Pursuant to	)	
G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 22, 2014, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua NC), to implement a Water System Improvement Charge (WSIC) and a Sewer System Improvement Charge (SSIC) for service rendered on and after January 1, 2015, in Aqua NC's Fairways and Beau Rivage service areas in New Hanover County, North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua NC's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua NC's last general rate case.

Commission Rules R7-39(h) and R10-26(h) specify that the WSIC and SSIC shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

The Public Staff carefully reviewed Aqua NC's stated WSIC and SSIC improvements, including a detailed review of invoices, materials lists, work orders, employee time sheets, and other accounting records, and filed a Report with recommendations on December 9, 2014.

ATTACHMENT B
Page 2 of 2

The following are the WSIC/SSIC charges Aqua NC applied for in its October 31, 2014 Application, the amount recommended by the Public Staff, and the Commission approved WSIC/SSIC:

	Aqua NC Applied for	Public Staff Recommendation	**Commission Approved**
WSIC	0.01%	0.00%	**0.00%**
SSIC	0.19%	0.14%	**0.14%**

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 31, 2014, the December 9, 2014 Public Staff Report, and the December 22, 2014 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e. for Docket No. key: W-218, Sub 363A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

ATTACHMENT C
Page 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semi-Annual Adjustments to Water and Sewer System Improvement Charges pursuant to G.S. 62-133.12	)	NOTICE TO CUSTOMERS IN AQUA NORTH CAROLINA SERVICE AREAS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated December 22, 2014, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua NC), to implement a Water System Improvement Charge (WSIC) and a Sewer System Improvement Charge (SSIC) for service rendered on and after January 1, 2015, in its service areas in North Carolina.

By Order entered in Docket No. W-218, Sub 363 on May 2, 2014, the Commission approved Aqua NC's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual water and sewer system improvement charge (WSIC/SSIC) adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua NC's last general rate case.

Commission Rules R7-39(h) and R10-26(h) specify that the WSIC and SSIC shall be applied to the total utility bill of each customer under the utility's applicable service rates and charges.

The Public Staff carefully reviewed Aqua NC's stated WSIC and SSIC improvements, including a detailed review of invoices, materials lists, work orders, employee time sheets, and other accounting records, and filed a Report with recommendations on December 9, 2014.

The following are the WSIC/SSIC charges Aqua NC applied for in its October 31, 2014 Application, the amount recommended by the Public Staff, and the Commission approved WSIC/SSIC:

ATTACHMENT C
Page 2 of 2

	Aqua NC Applied for	Public Staff Recommendation	**Commission Approved**
WSIC	0.21%	0.14%	**0.14%**
SSIC	0.44%	0.32%	**0.32%**

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed October 31, 2014, the December 9, 2014 Public Staff Report, and the December 22, 2014 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e. for Docket No. key: W-218 Sub 363A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the _22nd_ day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Reporting Requirements from Docket No.	)	
W-218, Sub 363 – Application by Aqua	)	
North Carolina, Inc., 202 MacKenan	)	ORDER APPROVING SECONDARY
Court, Cary, North Carolina 27511, for	)	WATER QUALITY IMPROVEMENT
Approval to Implement Secondary Water	)	PROJECTS
Quality System Improvement Projects	)	
Pursuant to G.S. 62-133.12	)	
	)	

BY THE COMMISSION: On December 3, 2014, Aqua North Carolina, Inc. (Aqua), filed an Application for Approval to Implement Secondary Water Quality System Improvement Projects Pursuant to G.S. 62-133.12 (Application).

On December 9, 2014, the Public Staff filed its Secondary Water Quality Report and Recommendations (Public Staff Report).

On June 12, 2013, North Carolina Session Law 2013-106 (House Bill 710), An Act to Permit Water Utilities to Adjust Rates for Changes in Costs Based On Third-Party Rates and to Authorize the Utilities Commission to Approve a Rate Adjustment Mechanism for Water and Sewer Utilities to Recover Costs for Water and Sewer System Improvements, was signed into law, having previously been ratified by the North Carolina General Assembly. In this legislation, the General Assembly, in pertinent part, enacted G.S. 62-133.12 to authorize the Commission in a general rate case proceeding to approve a rate adjustment mechanism to allow water and sewer utilities to recover reasonable and prudently incurred investments in eligible water and sewer system improvements. Session Law 2013-106 became effective on June 12, 2013. Prior to enactment of this legislation, the Commission did not have statutory authority to establish these rate adjustment mechanisms for water and sewer utilities.

G.S. 62-133.12 provides for Commission approval of a water system improvement charge (WSIC) and a sewer system improvement charge (SSIC), upon finding in the water or sewer utility's general rate case the rate adjustment mechanism is in the public interest.

WATER AND SEWER – FILINGS DUE PER ORDER OR RULE

On May 2, 2014, the Commission entered an Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice ("Rate Case Order") in Docket No. W-218, Sub 363, Aqua's general rate case. This order approved Aqua's request to utilize a WSIC/SSIC mechanism pursuant to G.S. 62-133.12 as the mechanism is in the public interest.

On June 6, 2014, the Commission entered an Order Adopting Rules to Implement G.S. 62-133.12 in Docket No. W-100, Sub 54. Rule R7-39, entitled "Water System Improvement Charge Mechanism," and Rule R10-26, entitled "Sewer System Improvement Charge Mechanism," were adopted effective as of the date of the rulemaking order.

Rules R7-39(f) and R10-26(f) provide that once WSIC and SSIC mechanisms are approved and eligible water and sewer system improvements are in service, the utility (in this case, Aqua) may file a request with the Commission for authority to impose the water and sewer system improvement charges pursuant to the mechanisms, to be effective no less than 60 days after filing the request.

G.S. 62-133.12(c)(2) and (c)(4) provide, in pertinent part, that specific approval from the Commission is necessary before Aqua may undertake and recover its incremental depreciation expense and capital costs through the WSIC mechanism for "eligible water system improvements" implemented to "comply with secondary drinking water standards."

Aqua's December 3, 2014, Application requested Commission approval of the following 19 secondary water quality improvement filtration projects:

System	County	Well Gallons Per Minute	Aqua Estimated Cost 000's
Coachman's Trail Well 4	Wake	690	$550-$565
Olde Mill Stream Well 3	Johnston	47	$145-$160
Devon Wells 1 & 3	Wake	280	$405-$420 (2)
Lake Rand Well 1	Wake	120	$270-$285
Stonebridge Well 17	Wake	122	$270-$285
Forest Glen Wells 1 & 2	Wake	34, 91	$10-$15 (1)
Holland Ridge Well 3	Wake	50	$5-$7.5 (1)
Greenfield Manor Well 2	Wake	27	$5-$7.5 (1)
Greymoss Wells 3, 5 & 6	Durham	30, 30, 114	$15-$22.5 (1)
Highland Trails Well 1	Wake	87	$5-$7.5 (1)

System	County	Well Gallons Per Minute	Aqua Estimated Cost 000's
Meadow Ridge Wells 1 & 2	Wake	60	$188-$203 (2)
Stoney Creek Wells 1 & 4	Wake	94	$295-$315 (2)
Stonecreek Well 18	Wake	45	$140-$155
Westmoor Well 1	Wake	95	$268-$283
Monticello Estates Wells 1 & 2	Guilford	50, 55	$10-$15 (1)
Springdale Wells 1 & 2	Guilford	58	$110-$125 (2)
Snow Creek Heights Well 2	Catawba	28	$113-$128
Belews Landing Wells 2 & 3	Rockingham	87	$10-$15 (1) (2)
Spencer Road Acres Well 3	Catawba	N/A	$5-$7.5
		Total	$2.82 Million-$3.02 Million

(1) The eight filtration projects footnoted (1) are disposable particulate cartridge filters.

(2) The five filtration projects footnoted (2) are one filter installation at a combined entry point to the distribution system.

The Public Staff Report and the Public Staff stated at the December 15, 2014, Regular Staff Conference (Staff Conference), that the Public Staff extensively reviewed each of the 19 filtration projects that Aqua submitted. The Public Staff provided Aqua an extensive list of requested information entitled WSIC Secondary Standards Public Staff Required Documents and Information attached to the Public Staff Report as Exhibit 1. Aqua did provide the Public Staff the requested information for each of the 19 filter projects. The Public Staff thoroughly reviewed each of the documents provided by Aqua. The Public Staff met with Aqua engineers and operations managers on ten occasions to discuss all the secondary water quality issues in these wells. The Public Staff also conducted selected site visits and discussed secondary water quality issues with customers.

The Public Staff based upon its review of the documents and discussions with Aqua's engineers and operations managers, recommended that the Commission approve each of the 19 applied for projects which address secondary standard water quality.

The Public Staff Report also stated the Public Staff strongly supports two additional secondary water quality processes as follows: a Comprehensive Water Main Flushing Program and a Comprehensive Customer Education Program to Minimize Secondary Water Quality Issues.

The Public Staff encouraged Aqua to continue its flushing program and increase the flushing frequency, if needed, to improve the secondary water quality.

The Public Staff encouraged Aqua to provide customers experiencing iron and manganese discoloration issues educational information to lessen the effects or impacts of discoloration.

The Public Staff Report stated that the Public Staff has observed that the sequestration treatment of iron and manganese with polyphosphates and orthophosphates on water from North Carolina water wells has been successful since the late 1970s. Sequestration coupled with comprehensive water main flushing programs has largely provided on many water systems adequate secondary standard water quality at a very reasonable cost. The Public Staff further stated the installation of filters such as manganese greensand are exponentially more costly, considering the filters' depreciation, return on rate base and backwash disposal, than sequestration coupled with adequate flushing.

The ten manganese greensand type filter projects Aqua has applied for excluding the unusually large Coachman Trail Well No. 4, total as estimated by Aqua $2.20 million to $2.36 million.

The Public Staff Report stated the Public Staff believes that the continued use of polyphosphates and/or orthophosphates, and/or Sea Quest as sequestrants, is a very economical treatment process for iron, manganese and hardness secondary water issues.

The Public Staff stated in the Public Staff Report and at Staff Conference that the Public Staff will continue to carefully and thoroughly review secondary water quality information and documentation presented by Aqua, including meeting with Aqua engineers and operations managers, conduct selected site visits, discuss secondary water quality issues with customers, and recommend when appropriate Commission approval of equipment and infrastructure installations.

Based upon the foregoing, Aqua's Application, the Public Staff Report, the Public Staff's statements at the December 15, 2014, Commission Regular Staff Conference and the entire record, the Commission concludes that Aqua should proceed to implement secondary standard water quality improvements through the installation of the applied for 19 filtration projects.

IT IS, THEREFORE, ORDERED that Aqua North Carolina, Inc., is authorized to implement the applied for 19 filtration projects to comply with secondary drinking water standards.

ISSUED BY ORDER OF THE COMMISSION.
This the _22nd_ day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

DOCKET NO. W-408, SUB 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by Public Staff for Appointment of Carolina Water Service, Inc. of North Carolina as Emergency Operator of the Nikanor Acres Section of Blue Ridge Manor Water System, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section Water Systems in Ashe County and Parkway East Water System in Wilkes County, North Carolina	)	ORDER APPOINTING EMERGENCY OPERATOR AND APPROVING INCREASED RATES

BY THE COMMISSION: On September 24, 2014, the Public Staff filed a Motion pursuant to G.S. 62-116(b) and G.S. 62-118(b), requesting the Commission to issue an order: (1) declaring an emergency, (2) appointing Carolina Water Service, Inc. of North Carolina (Carolina Water), as emergency operator, and (3) approving an emergency rate increase for the water systems serving the Nikanor Acres Section of Blue Ridge Manor Subdivision (Nikanor), the Ashe Lake – Beaver Creek Section, the Ashe Lake – Holiday Lane Section in Ashe County, and Parkway East Subdivision in Wilkes County, North Carolina.

Based upon the Public Staff's Motion and the Commission's records, the Commission makes the following

FINDINGS OF FACT

1. Cross-State Development Company (Cross-State) is the developer of each of these subdivisions.

2. In Docket No. W-408, Sub 0, the Commission issued an Order dated May 13, 1974, granting a certificate of public convenience and necessity (Certificate) to Cross-State to provide water utility service in the Nikanor Acres Section of the Blue Ridge Manor Subdivision (Nikanor). The same Order granted temporary operating authority (TOA) to provide water utility service to the Ashe Lake Section of Blue Ridge Manor Subdivision (Ashe Lake). This TOA is still in effect.

3. The Public Water Supply Section (PWSS) of the North Carolina Department of Environment and Natural Resources (NCDENR) is the state agency that now regulates the permitting, operations, and monitoring of community water systems in North Carolina. Previously, PWSS was known as the Division of Environmental Health (DEH).

4. DEH originally permitted Ashe Lake as one water system. However, in the 1980's DEH required this Ashe Lake system be divided into two DEH permitted and physically disconnected systems: Ashe Lake – Beaver Creek Section and Ashe Lake – Holiday Lane Section.

5. In general rate case order dated August 28, 1987, Docket No. W-408, Sub 3, the Commission ordered Cross-State to file a franchise application for its Parkway East water system in Wilkes County, North Carollina. Cross-State has never filed the application. DEH deregulated

the Parkway East system in May of 1992 because it was not a community water system due to its small size and population. Today, Parkway East is not regulated by PWSS as Parkway East is not a community water system.

6. On June 29, 1989, DEH placed the Nikanor and the Ashe Lake – Beaver Creek Section and the Ashe Lake – Holiday Lane Section water systems under a moratorium on expansion prohibiting further connections to the water systems without prior approval of plans and specifications by DEH. The moratorium is still in effect.

7. In Docket No. W-408, Sub 7, by Order issued October 29, 1999, the Commission ordered in Ordering Paragraph No. 5, "That the Applicant in a satisfactory manner rectify all deficiencies and comply with all recommendations made by Public Staff witnesses Vaughan and MacDonald as set out in the Evidence and Conclusion for Findings of Fact Nos. 16, 17, 18, 19, and 20." Cross-State has not rectified many of the specified deficiencies and each of the three Ashe County water systems is out of compliance with the Rules Governing Public Water Systems.

8. Cross-State has failed to complete many of the improvements for Ashe Lake – Beaver Creek Section and Ashe Lake – Holiday Lane Section, and Nikanor identified by PWSS regional Engineer Wade MacDonald at the April 29, 1999, hearing held in Docket No. W-408, Sub 7, and specified in Evidence and Conclusions No. 18 (A-E) of the Commission's October 29, 1999, Order. Cross-State has failed to complete any of the improvements in Nikanor listed in No. 18(G).

9. In Docket No. W-408, Sub 7, the Commission ordered in Ordering Paragraph No. 6, that "the Applicant file a written report with the Commission and the Public Staff delineating its progress in rectifying each deficiency and complying with each recommendation 90 days of the date of this Order, and every 90 days thereafter until the Commission orders otherwise." Cross-State failed to comply.

10. On October 19, 2009, in an email to Public Staff Utilities Engineer Bruce Vaughan, PWSS Engineer MacDonald identified deficiencies which place the systems in an ongoing state of emergency. In describing the Ashe Lake - Beaver Creek Section, Mr. MacDonald stated, "Rick Phillips (on-site operator) is the only reason this system remains in operation. If he becomes unavailable, this system will fail to provide water since he has to pamper it daily."

11. Cross-State's four water systems serve a total of 219 residential customers as follows:

		Customers
Nikanor		137
Ashe Lake – Beaver Creek Section		21
Ashe Lake – Holiday Lane Section		50
Parkway East		11
	Total	219

12. Operator Rick Phillips has 30 plus years of experience operating these four water systems. The Public Staff informed the Commission that the Public Staff has inspected these water

systems on a number of occasions accompanied by Rick Phillips. The Public Staff observed that Rick Phillips knows the systems extremely well and does an excellent job operating the systems with extremely limited equipment and resources.

13. By email dated June 20, 2013, to Don Raff, the president of Cross-State, PWSS Engineer Eric Hudson stated

> "On June 11, 2013, Clif Whitfield and I conducted inspections at the Blue Ridge Manor Subdivisions. Rick Phillips was very helpful and he appears to be doing a great job with limited resources. All of the storage tanks were full of water and all of the well house structures were clean and in good physical shape."

14. Carolina Water plans to retain Rick Phillips as contract operator for these four water systems.

15. Cross-State has incurred numerous notices of violation of the N.C. Drinking Water Act and the Rules Governing Public Water Systems, and has incurred PWSS administrative penalties for construction and operations violations.

16. PWSS in 2012 instituted a civil action in the Superior Court in Ashe County, North Carolina, 2012 CVS 101, to compel Cross-State to correct construction and operations violations of the N.C. Drinking Water Act and for collection of the PWSS assessed administrative penalty for these violations.

17. Cross-State and PWSS executed a Consent Judgment filed on December 2, 2013, in 2012 CVS 101 whereby Cross-State agreed to allow the Commission to appoint an emergency operator pursuant to G.S. 62-116(b), for the three Ashe County water systems.

18. Cross-State through its President Don Raff has advised the Public Staff that Cross-State consents to the Commission appointment of Carolina Water as the emergency operator of the Parkway East non-community water system in Wilkes County, and the three Ashe County water systems.

19. By letter from Don Raff, dated June 9, 2014, Cross-State described its precarious financial condition including pending shut offs of its electric service for non-payment, inability to pay a certified operator and conduct required water testing, difficulties making payroll and paying payroll taxes, the indebtedness to the on-site operator, Rick Phillips, for his paying Cross-State expenses out of his own pocket, and Cross-State's lack of interest in maintaining operations.

20. A dire emergency exists at these four Cross-State water systems, as Cross-State does not have the funds for necessary operations and system upgrades, the three Ashe County systems have marginal water supplies and are in substantial non-compliance with the Rules Governing Public Water Systems, and all four of the water systems are in imminent danger of losing adequate water utility service.

21. Carolina Water has approximately 40 years of experience managing and operating water systems in the North Carolina mountains. Currently Carolina Water manages and operates

mountain water systems in the following North Carolina counties: Alleghany, Avery, Buncombe, Cherokee, Henderson, Jackson, Madison, Rutherford, Transylvania, Watauga, and Yancey. The Public Staff advised the Commission that the Public Staff believes Carolina Water is extremely well qualified to be the emergency operator and is willing to perform the emergency service.

22. Carolina Water has agreed to be appointed emergency operator effective October 15, 2015. However, Carolina Water has requested that the Commission's order appointing Carolina Water emergency operator clearly state:

a. That Carolina Water as emergency operator shall not be responsible for, or liable for, any acts, omissions, system operations and maintenance, or system installations, occurring prior to the date of the appointment as emergency operator.

b. That Carolina Water as emergency operator may petition the Commission at any time to be discharged as the emergency operator, which discharge the Commission shall approve.

The Public Staff stated it fully supports the inclusion of both those provisions in the Commission's Order appointing Carolina Water as emergency operator.

23. The current rates for these four systems were approved in general rate case order dated October 29, 1999, Docket No. W-408, Sub 7, and are:

Metered Rates (Residential Service)	
Base charge, zero usage	$20.00
Usage charge, per 1,000 gallons	$ 6.17

The Commission in its Recommended Order Granting Partial Rate Increase and Assessing a Rate of Return Penalty, dated October 29, 1999, in Docket No. W-408, Sub 7, assessed as a penalty, a 100 basis point reduction to the approved operating margin due to inadequate system management and inadequate system design/construction.

24. The last three annual reports filed by Cross-State reflect the following net operating losses excluding accrued interest:

Annual Report Year	Net Operating Income (Loss)
2010	($7,574)
2011	($13,811)
2012	($2,156)

25. The Public Staff advised the Commission that the Public Staff believes the expenses listed on the 2010-2012 annual reports do not include all of the operational costs necessary for the three Ashe County systems to provide adequate service and be in compliance with the Rules Governing Public Water Systems. The Public Staff further stated that the Public Staff believes the

net operating losses in 2010-2012 would be significantly larger had the three Ashe County systems been operated in compliance with Rules Governing Public Water Systems. The Public Staff recommended the Commission approve a significant immediate emergency rate increase so the emergency operator Carolina Water will have adequate funds to operate the systems, perform necessary administrative functions, provide the necessary supplies, repair parts, replacement pumps, limited system improvements, compensate the contract operator, and have reserves for emergencies.

26. The Public Staff recommended that the Commission approve on a provisional basis, an emergency rate increase with the following rates:

Metered Rates (Residential Service)

Monthly base charge, zero usage	$28.00
Usage charge, per 1,000 gallons	$ 8.64

These Public Staff recommended rates will increase the average monthly residential bill 40% from $28.81 to $40.34 based upon the average monthly residential consumption of 1,428 gallons.

27. Cross-State does not have a bond posted with the Commission.

CONCLUSIONS

Based upon the foregoing and the recommendations of the Public Staff, the Commission concludes an emergency exists for the four Cross-State water systems which are in imminent danger of losing adequate water utility service. The Commission further concludes that Carolina Water System, Inc. of North Carolina, should be appointed emergency operator and the emergency rate increase recommended by the Public Staff to the monthly base charge for zero usage of $28.00 and usage charge per 1,000 gallons of $8.64, should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Carolina Water is hereby appointed as emergency operator of the Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section, and Parkway East water systems, effective October 15, 2014.

2. That a copy of this Order and Schedule of Rates, attached as Appendix A, shall be mailed with sufficient postage or hand delivered by Carolina Water to all customers served by the Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section, and Parkway East water systems, no later than ten days after the date of this Order and that Carolina Water submit to the Commission the attached Certificate of Service properly signed and notarized not later than 15 days after the date of this Order.

3. That the Schedule of Rates, attached as Appendix A, is approved effective October 15, 2014, on a provisional basis for water utility service provided Carolina Water as emergency operator of the Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section,

Ashe Lake – Holiday Lane Section, and Parkway East water systems, effective the date of this Order and Subject to refund of any amounts found unjust and unreasonable.

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 Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section, and Parkway East water systems, and the emergency operator's duties and responsibilities shall include, among others, the following:

(i) Regular inspections and testing of the three water systems in Ashe County;
(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 water 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 a mailing address.

c. That the emergency operator may contract with any person to carry out any of the duties necessary for operation and repair of the water 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 water 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 Public Water Supply Section of the Division of Environmental Health, the North Carolina Utilities Commission, the Public Staff of the Utilities Commission, and the Ashe County Health Department.

f. That the emergency operator shall collect from the customers of the water system such rates, assessments, and surcharges as may be approved by the North Carolina Utilities Commission and shall be fully authorized to bill and collect those rates, assessments, and surcharges and to disburse those funds as may be necessary to provide safe, reliable, and adequate water 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 North Carolina Utilities Commission.

g. That the emergency operator shall be entitled to all available records relating to the water 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, assessments (if any), and surcharges (if any), and all monies expended in the operation of the water system. In order to protect the customers' interests in the water 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 water utility system, including, but not limited to, construction of new wells or water treatment or storage facilities and the cost of the labor associated with those improvements, whether performed by the emergency operator or contractor hired by the emergency operator.

i. The emergency operator shall account for any funds advanced by it for operation of the water utility system.

j. That the emergency operator shall be responsible for and 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 Nikanor Acres Section of Blue Ridge Manor, Ashe Lake-Beaver Creek Section, Ashe Lake-Holiday Lane Section and Parkway East water systems pursuant to Commission Order. The emergency operator shall not be responsible for, or liable for, any acts, omissions, system operations and maintenance, or system installations, occurring prior to the date of the appointment as emergency operator. The disbursements by the emergency operator shall be made from the separate account set up by the emergency operator; the emergency operator shall account for any funds advanced by it for the operations.

k. That the emergency operator may petition the Commission at any time to be discharged as the emergency operator of the Nikanor Acres Section of Blue Ridge Manor, Ashe Lake – Beaver Creek Section, Ashe Lake – Holiday Lane Section, and Parkway East water systems, which discharge the Commission shall approve. Prior to its discharge, the emergency operator shall provide an acceptable accounting of 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 the petition to the Ashe County Health Department and the PWWS.

l. That this docket shall remain open for further motions, reports, etc., of the emergency operator, the PWSS, the Public Staff and for further orders of the Commission.

5. That the following items of information shall be made available to Carolina Water:

a. Customer information for each residence connected to the water 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 each electric service location needed for transfer of service.

c. Copy of each system plans and specifications.

d. Copies of all monitoring reports and evaluations completed by Cross-State or its certified operator for the past 24 months.

e. The names, addresses, and telephone number of all vendors providing materials and supplies for the water system operations.

f. Copies of all 2013 and 2014 (if available) property tax bills.

ISSUED BY ORDER OF THE COMMISSION.
This the _1st__ day of _October_, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

Commissioner James G. Patterson did not participate.

APPENDIX A

SCHEDULE OF RATES

for

CROSS-STATE DEVELOPMENT COMPANY
(Carolina Water Company, Inc. of North Carolina, Emergency Operator)

for providing water utility service in

NIKANOR ACRES SECTION OF BLUE RIDGE MANOR,
ASHE LAKE – BEAVER CREEK SECTION,
ASHE LAKE – HOLIDAY LANE SECTION
AND PARKWAY EAST WATER SYSTEMS

Ashe and Wilkes Counties, North Carolina

WATER RATES AND CHARGES

Metered Rates: (Residential Service)

Monthly base charge, zero usage	$28.00
Usage charge, per 1,000 gallons	$ 8.64

Reconnection Charge:

If water service cut off by utility for good cause:	$27.00
If water service discontinued at customer's request:	$27.00

If water service is reconnected to the same customer at the same address within nine months of disconnection, then the reconnection charge shall be the base charge times the number of months disconnected.

New Water Customer Charge:	$27.00
Bills Due:	On billing date
Bills Past Due:	25 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-408, Sub 9, on this the _1st_ day of _October_, 2014.

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-408, Sub 9, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________ 2014.

By: ___________________________________
Signature

____
Name of Utility Company

The above named Applicant, _______________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated ______________ in Docket No. W-408, Sub 9.

Witness my hand and notarial seal, this the ______ day of _____________ 2014.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ___________________________________
Date

DOCKET NO. W-1063, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by C&P Enterprises, Inc., Post Office Box 1472, Havelock, North Carolina 28532, for Authority to Increase Rates for Sewer Utility Service at Ocean Bay Villas and Ocean Glen Condominiums in Carteret County, North Carolina	)	RECOMMENDED ORDER GRANTING INCREASE IN RATES AND REQUIRING CUSTOMER NOTICE

HEARD IN: Courtroom 2, Room 206, Carteret County Courthouse, 300 Courthouse Square, Beaufort, North Carolina, at 7:00 p.m., on April 29, 2014

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For C&P Enterprises, Inc.:

No counsel of record

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BROWN, HEARING EXAMINER: On December 13, 2013, C&P Enterprises, Inc. (C&P or Applicant), filed an application with the Commission seeking authority to increase its rates for sewer utility service at Ocean Bay Villas and Ocean Glen Condominiums in Carteret County, North Carolina. By Order issued January 10, 2014, the Commission declared the matter to be a general rate case, suspended the proposed rates, and scheduled a hearing on April 29, 2014, in Beaufort, North Carolina, subject to cancellation if no significant protests were received subsequent to customer notice. The Order directed the Applicant to serve the Notice to Customers, attached as Appendix A to the Order, within 20 days after the date of the Order and to file the Certificate of Service attached to the Order within 45 days after the date of the Order.

On March 19, 2014, the Applicant filed a certificate of service indicating that the Notice to Customers had been mailed or hand delivered to customers on March 3, 2014.

On March 24, 2014, letters from officers of Ocean Bay Villas Owners Association, Inc., and Ocean Glen Condominiums protesting the proposed rate increase, were filed with the Commission.

On April 4, 2014, the Public Staff filed the affidavits of Charles M. Junis, Utilities Engineer with the Public Staff Water and Sewer Division, and Laura Bradley, Staff Accountant with the Public Staff Accounting Division.

On April 29, 2014, the public hearing was held as scheduled in Courtroom 2, Room 206, of the Carteret County Courthouse, 300 Courthouse Square, Beaufort, North Carolina, before Hearing Examiner Brown. Glen Whisler and Kevin Mullineaux testified at the hearing as public witnesses. The affidavits of witness Junis and Ms. Bradley were admitted into evidence, and witness Junis testified on behalf of the Public Staff.

Based upon the foregoing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. The Applicant is properly before the Commission seeking an increase in its rates and charges for sewer utility service.

2. That the Applicant has two customers, Ocean Bay Villas Owners Association, Inc. (Ocean Bay), and Ocean Glen Condominiums (Ocean Glen).

3. The Application listed the Applicant's revenues and expenses for the calendar year 2009, however, in its Order of January 10, 2014, the Commission established the 12-month period ended December 31, 2012, as the test year for this proceeding.

4. The Applicant's present and proposed rates are as follows:

	Present	Proposed
Flat Rate Sewer Utility Service:		
Per Residential Unit	$44.65	$57.15

5. The original cost rate base for use in this proceeding is $93,904, consisting of plant in service of $119,322, plus cash working capital of $5,496 and unamortized legal expenses of $24,065, less accumulated depreciation of $54,896 and average tax accruals of $83.

6. The appropriate level of total revenues for use in this proceeding is $47,686 under the Applicant's present rates and $61,036 under the proposed rates.

7. The appropriate level of operating revenue deductions under present rates for use in this proceeding is $57,083. Operating revenue deductions exclusive of interest expense, gross receipts tax, regulatory fee, and income taxes amount to $56,565.

8. The rate base method is the appropriate method for determining the Applicant's revenue requirement for sewer operations in this proceeding.

9. The rates proposed by the Applicant in this proceeding will produce an overall return of 4.21% on rate base. This return is not in excess of a reasonable level, and accordingly, the proposed rates are reasonable.

10. The rates proposed by the Applicant, as modified to reflect that the Applicant has only two customers, were recommended by the Public Staff and agreed to by the Applicant. These rates are as follows:

Monthly Flat Rate Sewer Utility Service:

Ocean Bay Villas	$2,914.65
Ocean Glen Condominiums	$2,171.70

11. The Applicant is providing adequate service to its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact appears in the record of the case and the testimony of public witness Whisler.

The record shows that the Applicant did not serve the Commission approved Notice to Customers on its customers by the deadline established in the Order of January 10, 2014, nor did it file the Certificate of Service by the applicable deadline. Witness Whisler stated that because of this violation, the application should be dismissed and the Applicant should be required to start over by filing a new application.

The Hearing Examiner agrees with witness Whisler that it is very important for a utility to comply with all Commission orders, and particularly with orders that establish procedures for notifying customers of pending Commission proceedings. However, on March 24, 2014, Ocean Bay and Ocean Glen each sent a letter of protest to the Executive Director of the Public Staff, expressing opposition to the proposed rate increase, and these letters were filed with the Commission. These letters were sent more than a month before the hearing, thus the customers (Ocean Bay and Ocean Glen) had adequate notice to prepare for the hearing. Ocean Glen's representative at the hearing chose not to testify and Ocean Bay did not even have a representative present.

The Hearing Examiner concludes that although the Applicant failed to serve its customers with notice of the hearing in a timely manner, or to file its Certificate of Service on time, the customers nevertheless had actual notice of the proposed rate increase, and they elected not to pursue their objection to the rate increase beyond the filing of a protest letter. Consequently, they were not prejudiced by the Applicant's violation of the January 10, 2014, Order and the Applicant is properly before the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence for this finding of fact appears in the record of the case and in the testimony of public witness Whisler and Public Staff witness Junis.

Public witness Whisler testified that he owns a condominium unit in Ocean Glen and he receives sewer utility service from the Applicant. As such, he asserted, he is a customer of the Applicant and was entitled to be served with the Notice to Customers. According to witness Whisler, there are a total of 89 unit owners in the two condominium complexes, and all of them, in his view, are the Applicant's customers. The witness noted that in its Application, the Applicant indicated that it had 89 customers; likewise, the Commission's Order of January 10, 2014, in this case, and its final order in the Applicant's last rate case (Docket No. W-1063, Sub 2), stated that there were 89 customers. If all 89 customers had received notice of the public hearing in this case, witness Whisler maintained, there would likely have been more public witnesses at the hearing.

On cross-examination, witness Whisler acknowledged that he is not billed by (and does not pay) the Applicant for sewer service. Instead, the sewer charges are paid by the homeowners' association and they are passed on to the unit owners through the association dues. In the past, the unit owners paid their bills directly to the Applicant, but some years ago the two homeowners' associations agreed to be responsible for payment of the sewer charges. [1]

The Hearing Examiner agrees with the Public Staff that the mere fact that witness Whisler benefits from the Applicant's service is not sufficient to make him a customer of the Applicant. A very broad definition of the term "customer," such as witness Whisler proposes, is not appropriate.

Accordingly, the Hearing Examiner concludes that a utility customer is a person or entity that receives service from, and is billed by, the utility. Ocean Bay and Ocean Glen are the Applicant's only customers. The Hearing Examiner notes that it is unfortunate that the Order and Customer Notice in this current docket does not reflect that the Applicant only has two customers as noted in the Recommended Order in Docket No. W-1063, Sub 2. Failure to reflect that, however, does not change the fact that there are only two customers, Ocean Bay and Ocean Glen.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence supporting this finding of fact appears in the record of the case and the testimony of public witness Whisler.

Witness Whisler testified that the financial data provided by the Applicant in its rate increase application were for the calendar year 2009. When witness Whisler became aware of the Public Staff's affidavits, he found that they were based on data for the twelve-month test period ending December 2012. In his opinion, this placed him at a handicap, because he did not know whether the Public Staff's data were audited data, and because he had inadequate time to review the data and take a position.

[1] The Hearing Examiner's Recommended Order in the Applicant's last rate case, Docket No. W-1063, Sub 2, states at page 3 that "C&P agreed to start billing the homeowners' associations for sewer service and stop billing the individual customers once it receives a request in writing from each homeowners association."

The Hearing Examiner cannot agree with witness Whisler regarding this. The Commission determined in its Order of January 10, 2014, that the test year for this proceeding should be the calendar year 2012 rather than 2009, so that the Applicant's rates could be set on the basis of current rather than older data. It is quite clear from the Public Staff's affidavits that the Public Staff audited the application extensively, and its recommendations were based on the results of its audit. The affidavits were filed on April 4, 2014, twenty-five days before the hearing, and this provided sufficient time for the Applicant or its customers to examine the data and take issue with the Public Staff's recommendations if they so desired. If any party felt that they needed more time, they could have filed a motion requesting the Commission to delay the hearing. No party chose to take any of these steps; all appear to have determined that the rates proposed by the Applicant, and endorsed by the Public Staff, were acceptable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-11

The evidence supporting these findings is contained in the records of this case, in the affidavits of Public Staff witnesses Junis and Bradley, and in the testimony of witnesses Whisler, Mullineaux, and Junis.

Based upon the entire record in this proceeding, the Commission finds and concludes that the Applicant has sufficiently demonstrated the need to increase its rates for providing sewer utility service. The Commission, therefore, concludes that the rates proposed by the Applicant and found reasonable by the Public Staff are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant is authorized to increase its rates for sewer utility service at Ocean Bay Villas and Ocean Glen Condominiums in Carteret County, North Carolina, as reflected in the Schedule of Rates attached hereto as Appendix A. These rates shall be effective for service rendered on and after the 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 a copy of the Notice to Customers attached hereto as Appendix B shall be mailed or hand delivered to both customers of the Applicant within five business days of the date of this Order, and that the Applicant shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than 15 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of September, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A

SCHEDULE OF RATES

for

C&P ENTERPRISES, INC.

for providing sewer utility service in

OCEAN BAY VILLAS AND OCEAN GLEN CONDOMINIUMS

Carteret County, North Carolina

Monthly Flat Rate Sewer Utility Service:

Ocean Bay Villas	$2,914.65
Ocean Glen Condominiums	$2,171.70

Reconnection Charge:	None
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-1063, Sub 3, on this the 15th day of September, 2014.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

NOTICE TO CUSTOMERS
DOCKET NO. W-1063, SUB 3
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that the North Carolina Utilities Commission has granted C&P Enterprises, Inc., a rate increase for sewer utility service in Ocean Bay Villas and Ocean Glen Condominiums in Carteret County, North Carolina. The rates approved by the Commission are as follows and were effective for service rendered on and after the date of this Notice:

Monthly Flat Rate Sewer Utility Service:

Ocean Bay Villas	$2,914.65
Ocean Glen Condominiums	$2,171.70

Reconnection Charge:	None
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 15th day of September, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief 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-1063, Sub 3, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________ 2014.

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-1063, Sub 3.

Witness my hand and notarial seal, this the ____ day of _______________ 2014.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ____________________________________
Date

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-354, SUB 336

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Adjust and Increase Rates For Water and Sewer Utility Service in All Service Areas in North Carolina, Excluding Nags Head	)	ORDER GRANTING PARTIAL RATE INCREASE, APPROVING RATE ADJUSTMENT MECHANISM, AND REQUIRING CUSTOMER NOTICE

HEARD IN: Onslow County Courthouse, 625 Court Street, Jacksonville, North Carolina, on Wednesday, September 18, 2013, at 7:00 p.m.

Currituck County Courthouse, Courtroom A, 2795 Caratoke Highway Currituck, North Carolina, on Thursday, September 19, 2013, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, September 30, 2013, at 7:00 p.m.

Buncombe County Courthouse, District Courtroom #1, 60 Court Plaza, Asheville, North Carolina, on Wednesday, October 2, 2013, at 7:00 p.m.

Watauga County Courthouse, 842 W. King Street, Boone, North Carolina, on Thursday, October 3, 2013, at 7:00 p.m.

Mecklenburg County Courthouse, Courtroom 5310, 832 East 4th Street, Charlotte, North Carolina, on Monday, November 4, 2013, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, December 2, 2013, at 1:00 p.m., and on Tuesday, December 3, 2013, at 9:30 a.m.

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

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Jo Anne Sanford, Sanford Law Office, Post Office Box 28085, Raleigh, North Carolina 27611-8085

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

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

For Corolla Light Community Association, Inc.:

Dwight W. Allen, Britton H. Allen, and Brady W. Allen, The Allen Law Offices, PLLC, 3737 Glenwood Ave., Suite 100, Raleigh, North Carolina 27612

BY THE COMMISSION: On May 29, 2013, Carolina Water Service, Inc. of North Carolina (Applicant, CWSNC, or Company), filed a letter notifying the North Carolina Utilities Commission (Commission) of its intent to file a general rate case as required by Commission Rule R1-17(a). On June 28, 2013, CWSNC filed an application for a general rate increase, requesting authority to adjust and increase rates for providing water and sewer utility service in all of its North Carolina service areas, excluding the Nags Head service area.

On July 9, 2013, CWSNC filed an amendment to its application, revising Appendix A-1, Page 4 of 8, to properly reflect the proposed monthly flat rate that would apply to sewer customers who do not receive water service from the Company and whose sewer service is not metered.

On July 16, 2013, the Commission issued an Order Establishing General Rate Case and Suspending Rates. Said Order stated that an order scheduling hearings and requiring customer notice would be issued by the Commission at a later date.

On August 13, 2013, the Corolla Light Community Association, Inc. (CLCA or Association) filed a petition to intervene. By Order issued August 19, 2013, the Commission granted the Association's petition to intervene.

On August 19, 2013, the Commission issued an Order Scheduling Hearings and Requiring Customer Notice. Said Order scheduled customer hearings in Jacksonville, Currituck, Raleigh, Asheville, Boone, and Charlotte, North Carolina and set the evidentiary hearing for Raleigh, North Carolina, to begin on December 2, 2013, preceded by another opportunity for customer comment. CWSNC was required to provide customer notice of the hearings and the proposed rate increase to all affected customers.

The intervention and participation in this docket by the Public Staff is made and recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). The CLCA is the only other intervenor in this proceeding.

On September 6, 2013, the Applicant filed its Certificate of Service indicating that customer notice had been given in accordance with Decretal Paragraph No. 8 of the Commission's August 19, 2013 Order.

WATER AND SEWER – RATE INCREASE

Public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this proceeding:

September 18, 2013	Jacksonville	No public witnesses testified.
September 19, 2013	Currituck	Dr. Teresa Blaxton, Richard R. Hoffman, Lynn E. Hoffman
September 30, 2013	Raleigh	Richard Yates, John Dye, Phillip Rice, Brad Atkinson, Nancy J. Hicks, Bain Jones, Alice Prescott, Elena Diamond, Karen Amato, Kiah Hicks
October 2, 2013	Asheville	Michael Maul, John Stockard, Bernie Apple, Chuck Van Rens, Ron Shuping
October 3, 2013	Boone	David Lane, Linda Norman, Ralph Norman, Marjorie Canaday, Arthur Canady, Harvey Bauman, Madeleine Haas, Michelle Sturm, Diane Starner, Terry Owen, Dan Donahue
November 4, 2013	Charlotte	Ron Taylor, Charles Smoot, Steve Googe, Mark Stevens, Whitney Henessee
December 2, 2013	Raleigh	William Staiano, Brady Dickson

CWSNC's responses to customer comments provided at the public hearings were contained in reports filed with the Commission as follows:

- October 1, 2013, consisting of five pages and addressing comments at the Jacksonville and Currituck public hearings;
- October 21, 2013, consisting of 18 pages and addressing the comments at the Raleigh public hearing;
- October 22, 2013, consisting of seven pages and addressing the comments at the Asheville public hearing;
- October 24, 2013, consisting of 17 pages and addressing the comments at the Boone public hearing;
- November 18, 2013, consisting of nine pages and addressing the comments at the Charlotte public hearing; and
- December 23, 2013, consisting of 10 pages and addressing the comments at the December 2, 2013 Raleigh public hearing.

On October 21, 2013, CWSNC filed the direct testimony and exhibits of Pauline M. Ahern, Principal, AUS Consultants, and Dimitry I. Neyzelman, Regulatory Accounting Manager, Utilities, Inc.

On November 7, 2013, the Public Staff filed a motion requesting that the Commission approve an extension of time for the filing of its testimony and intervenor testimony until November 19, 2013, and an extension for the Company to file rebuttal testimony until November 26, 2013. This motion was granted by Order issued on November 14, 2013.

On November 18, 2013, the Public Staff filed a second motion requesting that the Commission approve an extension of time for the filing of its testimony and intervenor testimony until November 21, 2013, and for the filing of rebuttal testimony by the Company until November 27, 2013. This motion was granted by Order issued on November 19, 2013.

On November 21, 2013, the Public Staff filed its third request for an extension of time, noting that the parties to this proceeding were close to reaching a settlement agreement. Therefore, the Public Staff requested an extension of time until November 25, 2013, for the Public Staff and intervenors to file testimony and/or a settlement agreement. The requested extension of time was granted by Commission Order issued November 22, 2013.

On November 25, 2013, the Public Staff filed its fourth request for an extension of time, stating that all of the parties to this proceeding had reached a settlement and needed additional time to finalize a stipulation and settlement agreement. Accordingly, the Public Staff requested an extension of time until December 2, 2013, for the parties to file testimony supporting a settlement agreement. The requested extension of time was granted by Commission Order issued November 26, 2013.

On November 27, 2013, CWSNC filed the supplemental testimony of Steven M. Lubertozzi, Chief Regulatory Officer, Utilities, Inc.; a motion for an order excusing witnesses Ahern, Neyzelman, and Lubertozzi from attending the evidentiary hearing, rescheduling proceeding, and accepting for filing and evidence the verifications by witnesses Ahern, Neyzelman, and Lubertozzi regarding their prefiled testimony; and a motion requesting that the record be held open to allow the Company until December 31, 2013, to complete certain specified construction projects.

On November 27, 2013, the Public Staff filed the testimony and exhibits of its witnesses, Michelle M. Boswell, Staff Accountant, Accounting Division; Gina Y. Casselberry, Utilities Engineer, Water Division; and Katherine A. Fernald, Supervisor, Accounting Division.

Also on November 27, 2013, a "Stipulation of Carolina Water Service, Inc. of North Carolina, the Public Staff and Corolla Light Community Association, Inc." (Stipulation) was entered and filed jointly by CWSNC, the Public Staff, and the CLCA (the Stipulating Parties), addressing and reflecting agreement on all contested issues in this proceeding.

On December 2, 2013, CWSNC filed its currently proposed three-year plan which provided a list of potential projects in support of its request for approval of a water system improvement charge (WSIC) and sewer system improvement charge (SSIC) rate adjustment mechanism in its general rate case, authorized by newly-enacted G.S. 62-133.12.[1]

On December 2, 2013, the matter came on for hearing, as scheduled. After the public witness testimony had been completed, the Presiding Commissioner thereafter found that good cause existed to:

1. Excuse the witnesses of CWSNC from appearing at the evidentiary hearing; provided, however, that CWSNC would provide a representative at the hearing to answer questions that may arise from the Commission and that the excused witnesses may be required to appear before the Commission and/or answer written interrogatories from the Commission should the need arise before the record is closed;

2. Postpone the presentation of the parties' stipulated agreement to the Commission until Tuesday, December 3, 2013;

3. Postpone the parties' presentation of expert witness testimony until Tuesday, December 3, 2013; and

4. Hold the record in this docket open for 29 days until December 31, 2013 to allow the Company to complete certain unfinished projects, with the understanding that the Company has agreed to extend the date upon which it would otherwise be entitled to place temporary rates in effect under bond pursuant to G.S. 62-135 by 29 days, or until Thursday, February 27, 2014.

The Presiding Commissioner's December 2, 2013 bench rulings were subsequently reduced to writing in an Order issued that same day.

On December 3, 2013, an evidentiary hearing was held by the Commission in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina. CWSNC presented the testimony of its Regional Director, Martin J. Lashua and witness Casselberry testified and presented exhibits on behalf of the Public Staff. The prefiled testimony and exhibits of Company witnesses Ahern, Neyzelman, and Lubertozzi were admitted into evidence. The prefiled testimony and exhibits of Public Staff witnesses Fernald and Boswell were also admitted into evidence.

Also on December 3, 2013, with a correction by an Errata Order issued on December 5, 2013, the Presiding Commissioner issued a Procedural Order in this docket which:

1. Holds the record in this docket open until January 8, 2014, to allow the Company to complete certain unfinished projects and to provide the Public

[1] On June 12, 2013, North Carolina Session Law 2013-106 (House Bill 710), An Act to Permit Water Utilities to Adjust Rates for Changes in Costs Based on Third-Party Rates and to Authorize the Utilities Commission to Approve Rate Adjustment Mechanism for Water and Sewer Utilities to Recover Costs for Water and Sewer System Improvements, was signed into law, having previously been ratified by the North Carolina General Assembly.

Staff with certain documentation regarding those projects; provided, however, that the record is held open with the understanding that the Company has again agreed to extend the date upon which it would otherwise be entitled to place temporary rates into effect under bond for an additional eight days until Friday, March 7, 2014; and

2. Requires briefs and/or proposed orders to be filed by the parties on or before Thursday, January 23, 2014.

On December 4, 2013, the Public Staff filed its Casselberry Late-Filed Exhibit 1, in response to the Commission's request at the December 3, 2013 evidentiary hearing, for the names of CWSNC's systems and number of customers who would remain on monthly flat rates for wastewater service, if the Stipulation is approved by the Commission.

On January 8, 2014, CWSNC filed a motion for extension of time to file an amended stipulation, including final updates on projects. By its motion, the Company requested an extension of time until Friday, January 10, 2014, to make its filing.

On January 9, 2014, the Commission issued an Order Holding Record Open and Extending Time, thereby granting the motion for extension of time filed by CWSNC on January 8, 2014.

On January 10, 2014, the Stipulating Parties filed an "Amended Stipulation of Carolina Water Service, Inc. of North Carolina, the Public Staff and Corolla Light Community Association, Inc." (Amended Stipulation), including Amended Stipulation Exhibits I and II, for consideration and approval by the Commission. In addition, the Stipulating Parties filed a Late-Filed Exhibit 2 consisting of a reconciliation schedule showing the revenue impact of the ratemaking adjustments agreed to by the Stipulating Parties as reflected in the Amended Stipulation.

On January 13, 2014, the Public Staff filed a late-filed exhibit concerning the WSIC and SSIC revenue requirements, consisting of a three-page narrative description which sets forth the understanding between the Public Staff and CWSNC as to how the WSIC and SSIC process will work and Schedules 1(a), 1(b), 1(c), 1(d), 2(a), 2(b), 2(c), and 3, which provide the Commission-requested WSIC and SSIC calculations. On that same date, CWSNC filed a late-filed exhibit to the testimony of witness Lashua, in response to the Commission's request for additional information at the December 3, 2013 evidentiary hearing. Witness Lashua's late-filed exhibit was admitted in evidence by Commission Order issued January 15, 2014.

On January 23, 2014, CWSNC and the Public Staff filed a Joint Proposed Order Granting Partial Rate Increase and Requiring Customer Notice.

Based on the application, the Amended Stipulation, the testimony and exhibits of the customer witnesses, the testimony and exhibits of CWSNC witnesses Ahern, Neyzelman, Lubertozzi, and Lashua, the reports filed by CWSNC in response to the testimony concerning service-related issues expressed by customers at the public hearings, the testimony and exhibits of Public Staff witnesses Boswell, Fernald, and Casselberry, and the entire record in this proceeding, the Commission is of the opinion that the provisions of the Amended Stipulation are just and reasonable.

Accordingly, the Commission now makes the following

FINDINGS OF FACT

1. CWSNC is a corporation duly organized under law and is authorized to do business in the State of North Carolina. CWSNC is a franchised public utility providing water and/or sewer utility service to customers in North Carolina. CWSNC is a wholly owned subsidiary of Utilities, Inc.[1]

2. CWSNC is properly before the Commission, pursuant to Chapter 62 of the General Statutes of North Carolina, for a determination of the justness and reasonableness of its proposed rates for its water and sewer utility operations, excluding the Nags Head service area.

3. CWSNC serves approximately 17,600 water customers and 11,344 sewer customers, including 878 customers in the Corolla Light and Monteray Shores service area, who are sewer-only customers. There are also approximately 1,550 water availability customers in the Company's Carolina Forest and Woodrun service areas. The Company's service territory spans 31 counties in North Carolina, from Nags Head in Dare County to Bear Paw in Cherokee County.

4. A total of 36 customers across CWSNC's service areas testified at the public hearings. Most of these customers testified in opposition to the magnitude of the rate increase proposed by the Company. Three of these customers testified in opposition to CWSNC's request for the Commission to approve a rate adjustment mechanism in this rate case proceeding, pursuant to G.S. 62-133.12, that would allow the Company to recover the incremental depreciation expense and capital costs associated with the Company's reasonable and prudently incurred investment in eligible water and sewer system improvements between general rate case proceedings. In addition, 17 of the total 36 customers expressed service-related concerns involving such matters as insufficient mowing and maintenance of property easements; low water pressure in the mountain systems; lack of capital improvements; lengthy water outages; discolored or distasteful water; staining on fixtures; hard water buildup on dishes; delayed billing resulting in the receipt of two bills in one month; billing errors; sediment in the water; noises in the pipes; slow response time by field and customer service personnel; and inadequate road repairs.

5. The overall quality of service provided by CWSNC is adequate.

6. The test year for purposes of establishing rates in this proceeding is the 12-month period ended June 30, 2012, updated for actual, known and measurable changes through December 31, 2013.

[1] Utilities, Inc. owns regulated utilities in approximately 15 states, including several in North Carolina. Presently, the regulated utilities owned by Utilities, Inc. in North Carolina are: (1) CWSNC; (2) Bradfield Farms Water Company; (3) Carolina Trace Utilities, Inc.; (4) CWS Systems, Inc.; (5) Elk River Utilities, Inc.; and (6) Transylvania Utilities, Inc.

7. The present water and sewer utility rates for the Company's North Carolina service territory, excluding the Corolla Light and Monteray Shores service area, have been in effect since February 10, 2011.[1] The present sewer utility rates for the Company's Corolla Light and Monteray Shores service area have been in effect since March 22, 2011.[2]

8. CWSNC's present and proposed water and sewer utility service rates are as follows:

<u>Water Utility Service</u>

<u>Monthly Metered Service</u> (Residential and Commercial):

	Existing	Proposed
Base Facilities Charges (zero usage)		
< 1" meter	$ 16.81	$ 20.65
1" meter	$ 42.03	$ 51.62
1½" meter	$ 84.05	$ 103.23
2" meter	$134.48	$ 165.17
3" meter	$252.15	$ 309.69
4" meter	$420.25	$ 516.15
6" meter	$840.50	$1,032.30

Usage Charge:	Existing	Proposed
A. Treated Water, per 1,000 gallons	$ 5.00	$ 6.14
B. Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 3.33	$ 3.33
Monthly Flat Rate Service:	$ 35.85	$ 44.03
Availability Rates (semi-annual):		
Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$ 20.00	$ 24.56

[1] In Docket No. W-354, Sub 324, an Order Granting Partial Rate Increase and Requiring Customer Notice was issued on February 10, 2011.

[2] In Docket No. W-354, Sub 327, an Order Granting Partial Rate Increase and Requiring Customer Notice was issued on March 22, 2011.

WATER AND SEWER – RATE INCREASE

Sewer Utility Service

Monthly Metered Service (Residential and Commercial):

		Existing	Proposed
A.	Base Facilities Charges (zero usage)		
	< 1” meter	$ 13.30	$ 15.99
	1" meter	$ 33.25	$ 39.98
	1½" meter	$ 66.50	$ 79.97
	2" meter	$106.40	$ 127.95
	3" meter	$199.50	$ 239.90
	4" meter	$332.50	$ 399.83
	6" meter	$665.00	$ 799.66
B.	Usage Charge, per 1,000 gallons (based on metered water usage)	$ 5.65	$ 6.79
C.	Minimum Monthly Charge	$ 40.14	$ 0.00
D.	Sewer customers who do not receive water service from the Company, per SFE (Single Family Equivalent)	$ 40.14	$ 48.27
Monthly Flat Rate Service:		$ 40.14	$ 48.27

Monthly Collection Service Only:
(When sewage is collected by utility and transferred to another entity for treatment)

		Existing	Proposed
A.	Single Family Residence	$ 14.50	$ 14.50
B.	Commercial/SFE	$ 14.50	$ 14.50

Mt. Carmel Subdivision Service Area:

	Existing	Proposed
Monthly Base Facility Charge	$ 5.41	$ 6.51
Usage Charge, per 1,000 gallons (based on metered water usage)	$ 4.71	$ 5.66

Regalwood and White Oak Estates Subdivision Service Areas:

Monthly Flat Rate Sewer Service:

	Existing	Proposed
Residential Service	$ 40.14	$ 48.27
White Oak High School	$1,249.55	$1,502.58
Child Castle Daycare	$ 155.34	$ 186.80
Pantry	$ 82.75	$ 99.51

Corolla Light and Monteray Shores:

Monthly Metered Service (Residential and Commercial):

	Existing	Proposed
A. Base Facilities Charges (zero usage)		
< 1” meter	$ 55.54	$ 71.19
1" meter	$ 138.85	$ 177.98
1½" meter	$ 277.70	$ 355.96
2" meter	$ 444.32	$ 569.53
3" meter	$ 833.10	$1,067.87
4" meter	$1,388.50	$1,779.78
6" meter	$2,777.00	$3,559.56
B. Usage Charge, per 1,000 gallons (based on metered water usage)	$ 7.06	$ 9.05

9. CWSNC, the Public Staff, and the CLCA entered into and filed a Stipulation on November 27, 2013, which settled all issues among all parties in this proceeding.

10. CWSNC, the Public Staff, and the CLCA entered into and filed an Amended Stipulation on January 10, 2014, reflecting the actual cost of plant additions placed in service by December 31, 2013.

11. Pursuant to the Amended Stipulation, CWSNC, the Public Staff, and the CLCA agree, among other things, that the levels of rate base, revenues and expenses set forth in Amended Stipulation Exhibit I, which are incorporated herein by reference, are the appropriate levels for use in this proceeding.

12. CWSNC requested an increase in its water and sewer utility service rates that would produce the following additional service revenues:

CWSNC Uniform – Water	$1,969,166
CWSNC Uniform – Sewer	$1,050,791
Corolla Light/Monteray Shores (CLMS) – Sewer	$ 325,637

13. CWSNC's present and proposed service revenues for the period ending June 30, 2012, are as follows:

SERVICE REVENUES

Water Utility Service:

	Present	Proposed
CWSNC	$8,629,952	$10,599,118

Sewer Utility Service:

	Present	Proposed
CWSNC	$5,207,389	$6,258,180
CLMS	$1,155,483	$1,481,120

14. CWSNC's original cost rate base is:

CWSNC Uniform – Water	$24,865,423
CWSNC Uniform – Sewer	$11,253,236
CLMS – Sewer	$ 6,087,805

15. The reasonable level of water and sewer plant in service for use in this proceeding, including pro forma adjustments, are as follows:

CWSNC Uniform – Water	$59,085,951
CWSNC Uniform – Sewer	$37,526,392
CLMS – Sewer	$13,179,837

16. Accumulated depreciation consists of the following balances for water and sewer operations:

CWSNC Uniform – Water	$14,628,548
CWSNC Uniform – Sewer	$ 9,758,083
CLMS – Sewer	$ 1,453,792

17. Contributions in aid of construction (CIAC), reduced by accumulated amortization of CIAC, consist of the following amounts for water and sewer operations:

CWSNC Uniform – Water	$13,010,095
CWSNC Uniform – Sewer	$12,908,470
CLMS – Sewer	$ 4,781,427

18. Post test year plant additions to be included in rate base for water and sewer operations through December 31, 2013, consist of the following amounts:

CWSNC Uniform – Water	$3,453,812
CWSNC Uniform – Sewer	$2,411,132
CLMS – Sewer	$ 107,085

19. CWSNC is entitled to recover total rate case costs of $346,058, as stipulated. The Stipulating Parties agree that these total rate case costs should be amortized over three years, resulting in annual rate case expense of $115,353, which would be allocated to each of the following entities as follows:

CWSNC Uniform – Water	$70,714
CWSNC Uniform – Sewer	$41,034
CLMS – Sewer	$ 3,605

20. It is reasonable and appropriate to calculate regulatory fees using the statutory rate of 0.13%.

21. It is reasonable and appropriate to calculate gross receipts tax based on the levels of revenues at the statutory rates of 4% for water operations and 6% for sewer operations. However, the Stipulating Parties acknowledge and agree that with the recent repeal of G.S. 105-116, as included in North Carolina Session Law 2013-316, effective July 1, 2014, water and sewer utilities will no longer have to pay a gross receipts tax.

22. It is reasonable and appropriate to make a downward adjustment to rates effective July 1, 2014, to recognize the reduction in the franchise/gross receipts tax for the Company, as stipulated. The Company should work with the Public Staff on the appropriate mechanism for effectuating this rate reduction and should file notice of the proposed rate reduction with the Commission by June 1, 2014, as stipulated.

23. On July 23, 2013, North Carolina Session Law 2013-316 (House Bill 998) was signed into law. Among other things, House Bill 998 reduced the state income tax rate for C corporations from the current rate of 6.9% to 6%, effective for taxable years beginning on or after January 1, 2014. The Act further reduces the rate from 6% to 5% effective for taxable years beginning on or after January 1, 2015. It is reasonable and appropriate to calculate state income taxes based on the statutory corporate rate effective January 1, 2014, of 6%.

24. It is reasonable and appropriate that a downward adjustment should be made to recognize the reduction in the state corporate income tax rate from 6% to 5%, beginning on January 1, 2015, as stipulated. The Company should work with the Public Staff on the appropriate mechanism for effectuating this rate reduction, and should file notice of the proposed rate reduction with the Commission by December 1, 2014, as stipulated. It is reasonable and appropriate to calculate federal income taxes based on the statutory corporate rate of 34%.

25. CWSNC's total operating revenue deductions under present rates are:

CWSNC Uniform – Water	$7,303,394
CWSNC Uniform – Sewer	$4,686,920
CLMS – Sewer	$ 833,270

26. The prefiled testimony of CWSNC witness Ahern and the supplemental prefiled testimony of CWSNC witness Lubertozzi provided adequate evidence in support of the capital structure, long-term debt cost rate, and the return on common equity rate agreed to by the Stipulating Parties.

27. The reasonable and appropriate capitalization ratios for ratemaking purposes in this proceeding are the actual capital structure of Utilities, Inc. at September 30, 2013; the reasonable and appropriate embedded cost of debt is the Company's filed rate of 6.60%; and a return on common equity of 9.75% is reasonable and appropriate, as stipulated. Accordingly, the just, reasonable and appropriate components of rate of return for CWSNC, for use in this proceeding, are as follows:

a. Long-Term Debt Ratio:	49.73%
b. Common Equity Ratio:	50.27%
c. Embedded Cost of Debt:	6.60%
d. Return on Common Equity:	9.75%
e. Overall Weighted Rate of Return:	8.18%

28. It is reasonable and appropriate for the Applicant, pursuant to the "Stipulation of Carolina Water Service Inc. of North Carolina and the Public Staff" approved in Docket No. W-354, Sub 324 (Sub 324 Stipulation),[1] to begin charging, effective as of the date of the final Order issued in this general rate case proceeding, a monthly metered sewer rate for residential sewer customers who also receive metered water service from CWSNC.

29. In this proceeding, it is reasonable and appropriate for the current, system-specific sewer rates for the CLMS service area to remain unchanged from those established in Docket No. W-354, Sub 327 and the Company's remaining revenue sewer requirement to be recovered through its uniform sewer rates for other systems, as stipulated. In future general rate case proceedings, the issue of rate disparity should be reviewed again by CWSNC, the Public Staff, and any other interested party and appropriate consideration should be given to moving the CLMS service area toward uniform rates in light of the facts and circumstances that exist at that time, as stipulated.

30. CWSNC is entitled to changes in rates that will produce the following levels of service revenues:

CWSNC Uniform – Water	$9,704,381
CWSNC Uniform – Sewer	$6,145,062
CLMS – Sewer	$1,155,483

[1] The Sub 324 Stipulation was entered and filed on December 1, 2010.

WATER AND SEWER – RATE INCREASE

31. The Stipulating Parties' agreed-upon rates will produce the following additional levels of service revenues for water and sewer operations:

CWSNC Uniform – Water	$1,074,429
CWSNC Uniform – Sewer	$ 937,673
CLMS – Sewer	$ 0

32. The water and sewer utility service rates and charges agreed to by CWSNC, the Public Staff, and the CLCA, as provided in Amended Stipulation Exhibit II, are as follows:

Water Utility Service

Monthly Metered Service (Residential and Commercial):

Base Facilities Charges (zero usage)

< 1" meter	$ 19.19
1" meter	$ 47.98
1½" meter	$ 95.95
2" meter	$153.52
3" meter	$287.85
4" meter	$479.75
6" meter	$959.50

Usage Charge:

A.	Treated Water, per 1,000 gallons	$ 5.62
B.	Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 3.75

Monthly Flat Rate Service: $ 36.06

Availability Rates (semi-annual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$ 22.50

Sewer Utility Service

Monthly Metered Service:

A. Base Facilities Charges (zero usage)

Residential	$ 18.68

Commercial

< 1" meter	$ 18.68
1" meter	$ 46.70
1½" meter	$ 93.40
2" meter	$149.44
3" meter	$280.20
4" meter	$467.00
6" meter	$934.00

B. Usage Charge, per 1,000 gallons (based on metered water usage)	$ 7.95
C. Sewer customers who do not receive Water service from the Company, per SFE (Single Family Equivalent)	$ 56.45

<u>Monthly Flat Rate Service</u>:	$ 56.45

<u>Monthly Collection Service Only</u>:
(When sewage is collected by utility and transferred to another entity for treatment)

A. Single Family Residence	$ 20.33
B. Commercial/SFE	$ 20.33

<u>Mt. Carmel Subdivision Service Area</u>:

Monthly Base Facility Charge	$ 7.58
Usage Charge, per 1,000 gallons (based on metered water usage)	$ 5.45

<u>Regalwood and White Oak Estates Subdivision Service Areas</u>:

Monthly Flat Rate Sewer Service:

Residential Service	$ 56.45
White Oak High School	$1,751.85
Child Castle Daycare	$ 217.80
Pantry	$ 116.00

<u>Corolla Light and Monteray Shores</u>:

Monthly Metered Service (Residential and Commercial):

A. Base Facilities Charges (zero usage)

< 1” meter	$ 55.54
1" meter	$ 138.85
1½" meter	$ 277.70
2" meter	$ 444.32
3" meter	$ 833.10
4" meter	$1,388.50
6" meter	$2,777.00

B. Usage Charge, per 1,000 gallons (based on metered water usage) $ 7.06

33. The rates agreed to by CWSNC, the Public Staff, and the CLCA, as set forth in Amended Stipulation Exhibit II, and as provided hereinabove and included in Appendices A-1 and A-2, attached hereto, are just and reasonable and should be approved.

34. The following connection fees for the Carolina Pines and Amherst Subdivisions were inadvertently omitted from the schedule of rates in Docket No. W-354, Sub 324, and should be added to the Company’s schedule of rates as follows:

Amherst Subdivision:

Connection fees:

Water	$250
Sewer	$500

Carolina Pines Subdivision: (Sewer only)

Connection charges:

Residential	$1,350 per unit including Single Family Homes, Condominiums, Apartments, and Mobile Homes
Hotels	$750 per unit
Nonresidential	$3.57 per gallon of daily design of discharge or $900 per unit, whichever is greater

35. CWSNC shall install all meters and fully meter the unmetered systems in Powder Horn, Misty Mountain, Crystal Mountain, Watauga Vista, High Meadows, Ski Country (a part of Sugar Mountain), and Mt. Mitchell, before the evidentiary hearing in the Company’s next general rate case proceeding, as stipulated. CWSNC shall immediately switch customers to metered rates as soon as each system is fully metered, as stipulated.

36. CWSNC shall modify its billing system such that the Company has the capability to generate reports that reflect the actual number of customers each month (not the number of bills produced each month) or shall change its policy concerning billing cycles such that customers shall be billed only once per month, as stipulated.

37. CWSNC shall maintain accurate records for all metered sewer customers such that in the next general rate case proceeding residential customers with meter sizes greater than 5/8 inch will be charged the same rate as commercial customers with the same meter size.

38. CWSNC shall include in its NCUC Form W-1 filing in its next general rate case the following, as stipulated: an individual spreadsheet for each service area, which shows the number of actual customers served for each meter type, and the actual usage for each meter type for each month for the 12-month test period specified in its application; and a spreadsheet summarizing the total number of active customers and total usage for each billing type for each month for the 12-month test period specified in its application.

39. The Company's just and reasonable pump and haul expenses and spray charges incurred in its Belvedere system should be amortized over a period of 10 years, as stipulated.

40. The Applicant's request to increase the charge for processing non-sufficient-funds (NSF) checks from $15.00 to $25.00 is reasonable and should be approved.

41. The Stipulating Parties agreed that any Order approving rates and charges as set forth in the Amended Stipulation may become the final Order of the Commission upon issuance and they waive their respective rights to file exceptions and appeal the final Order of the Commission incorporating the stipulated matters.

42. The Stipulating Parties acknowledged that the Amended Stipulation is the product of give-and-take discussions and resulted from extensive negotiations and compromise. The Amended Stipulation contains the provision that the agreements made in the Amended Stipulation do not bind the Stipulating Parties to the same positions in future proceedings, and the Stipulating Parties reserve the right to take different positions in any future proceedings.

43. In its general rate case application, the Company also requested Commission approval of a rate adjustment mechanism for recovery of water and sewer system improvements charges for infrastructure projects completed between general rate case applications as provided for in the newly enacted G.S. 62-133.12, which became effective on June 12, 2013.

44. The Commission's August 19, 2013 Order Scheduling Hearings and Requiring Customer Notice required that CWSNC notify its customers that it was requesting Commission authorization, pursuant to G.S. 62-133.12, to implement a WSIC and SSIC mechanism designed to recover between general rate case proceedings the costs associated with investment in certain completed, eligible projects for system or water quality improvements. Such customer notice also stated that any cumulative system improvement charges recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding.

45. On September 6, 2013, the Company filed its Certificate of Service certifying that notice had been provided to customers in accordance with the terms and conditions specified in the Commission's August 19, 2013 Order.

46. On December 2, 2013, the Company filed a three-year plan which contained a list of potential construction of projects that CWSNC believes to be eligible for recovery through the rate adjustment mechanism pursuant to G.S. 62-133.12.

47. The General Assembly has recognized a need in North Carolina to incentivize water and sewer utilities to invest in needed infrastructure improvements. The enactment of G.S. 62-133.12 should encourage and accelerate investment in needed water and sewer infrastructure by means of a mechanism which will alleviate the effects of regulatory lag by allowing for earlier recovery of some portion, not to exceed 5% of approved service revenues, of the incremental depreciation expense and capital costs associated with eligible investments in water and sewer infrastructure projects completed and placed in service between general rate case proceedings.

48. CWSNC would be incentivized and encouraged to accelerate its investment in water and sewer infrastructure improvements to comply with applicable water quality and effluent standards, including secondary water quality standards, if authorized to utilize a WSIC/SSIC mechanism to alleviate the effects of regulatory lag.

49. It is in the public interest to authorize CWSNC to utilize a rate adjustment mechanism to recover the incremental depreciation expense and capital costs related to eligible investments in water and sewer infrastructure projects completed and placed in service between general rate case proceedings as provided for in the newly enacted G.S. 62-133.12.

50. In Section 17 of the Amended Stipulation, CWSNC, the Public Staff, and the CLCA acknowledged that the rulemaking establishing the procedures for implementing the WSIC and SSIC mechanism is pending before the Commission in Docket No. W-100, Sub 54, and that the final rules on the WSIC/SSIC mechanism have not yet been approved. The Stipulating Parties agreed that approval of the WSIC/SSIC mechanism in this proceeding and the WSIC/SSIC Rulemaking should be coordinated and, therefore, recommended that this docket be held open, or that the Commission adopt an alternative procedure in this docket, so that the Company can make the requisite filings and qualify for implementation of the system improvement charges under the rules adopted by the Commission without having to make an additional rate case filing.

51. In Section 18 of the Amended Stipulation, the Stipulating Parties agreed to recommend the following to the Commission:

> (1) That the Company file in this proceeding any additional information required as a result of the WSIC/SSIC Rulemaking within thirty days after the Commission issues its final rules in the WSIC/SSIC Rulemaking. For example, recommended Rules R7-39(c)(1) and R10-26(c)(1) require that a three-year plan be filed with the request for approval of a WSIC/SSIC mechanism in a general rate case.

(2) That the Public Staff be allowed to file comments and recommendations concerning the Company's proposed WSIC/SSIC mechanism in this proceeding within 30 days after the Company files the additional information required by the Commission in its rulemaking.

52. In Section 19 of the Amended Stipulation, the Stipulating Parties acknowledged that Recommended Rules R7-39(n) and R10-26(n) require that the following reports be filed within 45 days after the end of each calendar quarter and in a format prescribed by the Commission: (1) a quarterly earnings report, (2) a quarterly report of WSIC/SSIC collections from customers, and (3) a construction status report. The Stipulating Parties agreed that the following format for these reports should be established in this proceeding:

(1) Quarterly Earnings Report – The quarterly earnings report shall consist of the following:

(a) A balance sheet and income statement for the calendar quarter and calendar year to date for CWSNC;

(b) A statement of the per books net operating income for the calendar quarter and calendar year to date for each rate division (CWSNC uniform water, CWSNC uniform sewer, CLMS sewer operations, and Nags Head sewer operations) based on North Carolina ratemaking and in the same format as the Per Books column on Schedule B of the Company's application;

(c) A statement of rate base at the end of the calendar quarter for each rate division based on North Carolina ratemaking in the same format as the Per Books column on Schedule C of the Company's application; and

(d) The number of customers and gallons sold for each month of the calendar quarter for each rate division by rate type (meter size, flat rate, etc.).

(2) Quarterly Report on WSIC/SSIC Collections – The quarterly report on WSIC/SSIC collections should provide the calculation of the WSIC/SSIC amounts collected for the quarter by rate division and rate type.

(3) Quarterly Construction Status Report – The construction status report should include by rate division the following information for each eligible system improvement project: (a) the cost incurred during the quarter, (b) the cumulative amount incurred, (c) the estimated total cost for the project, (d) the estimated completion date, and (e) the actual completion date.

53. It is reasonable and appropriate to adopt the alternative procedures set forth in Appendices C and D of this Order, which are expressly incorporated herein, so that CWSNC can make the requisite filings and qualify for implementation of the system improvement charges

without having to make an additional rate case filing subsequent to the adoption of final rules in Docket No. W-100, Sub 54.

54. CWSNC shall work with the Public Staff to develop and implement a plan to identify and respond to secondary water concerns that occur in significant numbers in individual subdivision service areas. At a minimum, this plan shall require the Company and the Public Staff to file a written report with the Commission on June 1 and December 1 each year in which the WSIC is in effect on secondary water quality concerns that are affecting its customers. Such report shall contain a recommendation as to whether the Commission should order CWSNC to pursue corrective action and/or an underlying reason(s) why the action should or should not be undertaken.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

The evidence for the foregoing findings of fact is contained in: the application; the Commission records; the testimony of the public witnesses; the testimony and exhibits of CWSNC witnesses Ahern, Neyzelman, Lubertozzi, and Lashua; the service quality reports filed by the Company in response to customer testimony at public hearings; the testimony and exhibits of Public Staff witnesses Boswell, Fernald, and Casselberry; and the Amended Stipulation.

Public Hearings

With respect to customer concerns expressed in this proceeding, Public Staff witness Casselberry testified that the Public Staff received approximately 107 email messages or letters from CWSNC customers, a petition from Woodhaven Subdivision with 68 signatures, and a petition from Pleasant Hill Subdivision with 13 signatures. Witness Casselberry observed that 17 complaints were from the CLMS service area, 21 from High Meadows Subdivision, 36 from Misty Mountain, nine from other mountain systems, five from Amherst Subdivision, and the remaining 19 from various CWSNC's service areas across North Carolina. Witness Casselberry commented that most of the customers objected to: the magnitude of the rate increase; no justification for an increase; the proposed rate of return; and/or no improvements to their specific system. Six public hearings were held across the State for the receipt of customer testimony.[1]

Regarding evidence received at public hearings concerning service-related complaints, no public witnesses appeared at the public hearing in Jacksonville on September 18, 2013. Three witnesses appeared and presented testimony at the customer hearing held in Currituck on September 19, 2013, all of whom objected to the proposed rate increase, but brought forward no service complaints. Ten public witnesses appeared at the public hearing in Raleigh on September 30, 2013; five of those witnesses addressed service-related issues, which were further investigated by the Company and addressed in a written follow-up report. At the October 2, 2013 public hearing in Asheville, five witnesses appeared, but only one customer raised any issue related to service, while several customers made positive comments about the service, Company personnel, and/or

[1] Customers who were unable to attend the public hearings were provided the opportunity to be heard at the December 2, 2013 evidentiary hearing held in Raleigh, North Carolina.

water quality. The Company filed a written report to specifically address and respond to the testimony received from customers at the Asheville public hearing.

Of the 11 witnesses who appeared and testified at the public hearing held in Boone on October 3, 2013, six spoke to service or quality complaints which the Company addressed in detail in its written report. Two of these 11 witnesses testified in opposition to CWSNC's request for the Commission to approve a rate adjustment mechanism pursuant to newly enacted G.S. 62-133.12. Five witnesses testified at the public hearing in Charlotte on November 4, 2013, and three of those witnesses spoke to service or quality complaints which the Company addressed with specificity in its written follow-up report. Two witnesses testified in expression of their concerns about rates and service at the public hearing in Raleigh on December 2, 2013. CWSNC responded to these customer complaints in its post-hearing report. One of those two witnesses expressed opposition to the Company's request for the Commission to approve a WSIC/SSIC mechanism. There were no outstanding service issues to be addressed or followed up by the Company as a result of the matters raised at the evidentiary hearing on December 3, 2013.

Witness Casselberry testified that, as part of her investigation of the water and sewer systems operated by CWSNC, she contacted all of the regional offices of the Surface Water Protection Sections (SWPS) and Public Water Supply Sections (PWSS) of the North Carolina Department of Environment and Natural Resources (NC DENR) and that none of the regional office personnel expressed any major concerns with the systems serving CWSNC customers or major issues concerning the Company's water quality. In addition, witness Casselberry generally reviewed the scope and nature of the customer complaints contained in the record as set forth and reflected in emails, letters, petitions, and testimony at public hearings. Witness Casselberry testified that she had reviewed all of the reports filed by the Company in response to customer service complaints voiced at the public hearings and stated that she was satisfied with the Company's responses concerning service and water quality issues. No party contested the contents of any of the service reports filed by the Company.

Based on the foregoing, and a careful review of the testimony at public hearings, the Company's written reports regarding customer service complaints and concerns, and the Public Staff's engineering and service quality investigation, the Commission concludes that CWSNC has adequately addressed the service-related concerns expressed by public witnesses, and that the overall quality of service provided by the Company is adequate.

<u>Return on Common Equity</u>

In its application, the Company requested an overall cost of capital of 8.80%, which included a return on common equity component of 11.14%. In support of such request, CWSNC witness Pauline Ahern prefiled testimony on October 21, 2013. Witness Ahern testified that the results of market-based cost of common equity models – i.e., the Discounted Cash Flow (DCF) approach, the Risk Premium Model (RPM), and the Capital Asset Pricing Model (CAPM) - provided returns on common equity of 8.95%, 11.26%, and 10.63%, respectively, without consideration of her proposed adjustments for financial risk and business risk. Based upon her studies and judgment, witness Ahern determined that the indicated common equity cost rate for CWSNC was 10.65%, which she increased by a financial risk adjustment of 0.09% and a business risk adjustment of 0.40% to arrive at her recommended common equity cost rate for CWSNC of 11.14%.

Witness Ahern maintained that assuring that the utility can fulfill its obligations to the public while providing safe and reliable service at all times requires a level of earnings sufficient to maintain the integrity of presently invested capital as well as permitting the attraction of needed new capital at a reasonable cost in competition with other firms of comparable risk. Witness Ahern stated that such principles are consistent with the fair rate of return standards established by the U.S. Supreme Court in the Hope[1] and Bluefield[2] decisions. Consequently, marketplace data must be relied upon in assessing a common equity cost rate appropriate for ratemaking purposes. Witness Ahern testified that her recommended common equity cost rate is based upon marketplace data for a proxy group of utilities as similar in risk as possible to CWSNC. Witness Ahern maintained that both the use of the market data for the proxy group and the use of multiple common equity cost rate models adds reliability when arriving at a recommended common equity cost rate.

Witness Ahern concluded that a common equity cost rate of 11.14% is consistent with the Hope and Bluefield standards of a fair and reasonable return which ensures the integrity of presently invested capital and enables the attraction of needed new capital on reasonable terms. She contended that it also ensures the continued reliability and quality of service to the benefit of ratepayers; thus, balancing the interests of both ratepayers and CWSNC.

Furthermore, witness Ahern concluded that a common equity cost rate of 11.14% is also reasonable in light of current and expected economic and capital market conditions. Based upon her detailed analyses, witness Ahern opined that "the end of the low interest rate environment of the last five years or so, a product of Fed policy, is coming to a close sooner rather than later and capital costs will continue to rise in general in the months and years to come".

In supplemental testimony, Company witness Lubertozzi addressed the capital structure and return on equity component of the overall rate of return of 8.18% that the Stipulating Parties agreed to in their Amended Stipulation. Witness Lubertozzi testified that the Applicant updated its capital structure to Utilities, Inc.'s actual capital structure as of September 30, 2013,[3] which consisted of 49.73% long-term debt and 50.27% common equity. Witness Lubertozzi stated that during the course of its investigation the Public Staff accepted the Company's updated capital structure and the Stipulating Parties agreed, as an integral part of the Stipulation, that the appropriate capital structure to use to establish rates in this proceeding was 49.73% long-term debt and 50.27% common equity. Witness Lubertozzi noted that the use of Utilities, Inc.'s actual capital structure in this proceeding is consistent with the capital structure adopted by the Commission in the Company's last general rate case proceeding in Docket No. W-354, Subs 324 and 327, which was based on Utilities, Inc.'s actual capital structure at September 30, 2010.

[1] Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[2] Bluefield Waterworks & Impr. Co. v. Public Service Comm'n, 262 U.S. 679, 692-93 (1923).

[3] In its application, CWSNC included the actual capital structure of Utilities, Inc. at June 30, 2012, which consisted of 51.57% long-term debt and 48.43% common equity.

Witness Lubertozzi testified that CWSNC, the Public Staff, and the CLCA had agreed for settlement purposes that a 9.75% return on common equity was appropriate for use in this proceeding. Witness Lubertozzi stated that he initially based his opinion to support such negotiated return on common equity on a review of the prefiled testimony of witness Ahern which utilized the DCF, RPM, and CAPM market-based cost of equity models to determine the cost of equity for CWSNC. Witness Lubertozzi commented that, although the stipulated return on common equity of 9.75% falls substantially below witness Ahern's formal recommendation of 11.14%, support for it, considered in the context of the entire record and the many factors which influenced the final settlement in this proceeding, is found at least partially in the fact that it falls within the range of the study results (8.95% - 11.26%) from the three models she employed in developing her recommendation. Witness Lubertozzi pointed out that the 9.75% return on common equity is 151 basis points lower than witness Ahern's RPM result and 88 basis points lower than her CAPM result. While the stipulated return on common equity is 80 basis points higher than witness Ahern's DCF study result, witness Lubertozzi testified that it is nevertheless in the lower range of her three studies taken together.

Witness Lubertozzi asserted that the evidence in this proceeding clearly supported a finding and conclusion that the stipulated return on common equity was just, reasonable, and fair to all parties, including consumers, in light of changing economic conditions within the State. In support of his opinion (in addition to the foregoing), witness Lubertozzi observed that the stipulated return on common equity of 9.75% was:

- 139 basis points lower than the Company's requested equity return of 11.14%, which is supported by the prefiled testimony of witness Ahern;
- 45 basis points lower than the return on equity of 10.2% approved in CWSNC's last general rate proceedings in North Carolina in 2011; and
- significantly below the rate of return on common equity (10.2%) allowed by the Commission for Duke Energy Carolinas, LLC and Duke Energy Progress, Inc. in their most recent 2013 general rate proceedings, as well as the return on equity of 10.0% allowed in the recently-decided 2013 general rate case for Piedmont Natural Gas Company, Inc. in Docket No. G-9, Sub 631.

Witness Lubertozzi commented that the foregoing and other factors support the conclusion that the settlement among the Stipulating Parties on return and capital structure issues is just, reasonable, and takes into account relevant factors required to be considered by relevant statutory and case law. Witness Lubertozzi further observed that the total cost of capital for CWSNC resulting from the settlement of 8.18%, which is a product of the debt and equity costs reflected in the settlement, results in a 22 basis point reduction from the overall cost of capital of 8.40% approved by the Commission in CWSNC's last general rate cases in 2011. Witness Lubertozzi contended that the settled return on common equity represented a fair balance between the financial interests of consumers and the Company as it continues to make substantial investments in the water and sewer utility systems it operates in order to continue to provide high-quality service to its customers in North Carolina.

G.S. 62-133(b)(4) requires the Commission to fix rates for service which will enable a public utility, by sound management, to (a) produce a fair profit for its stockholders, in view of current economic conditions; (b) maintain its facilities and services; and (c) compete in the market for capital on reasonable terms, and no more. This is the ultimate objective of ratemaking. Utilities Commission v. General Telephone Company, 281 N.C. 318, 189 S.E.2d 705 (1972).

Based upon the prefiled testimony of CWSNC witnesses Ahern and Lubertozzi, the Commission is of the opinion (a) that the evidence of record supports the return on equity of 9.75% as agreed to by the Stipulating Parties and (b) that such return should allow CWSNC a reasonable opportunity to accomplish the ultimate objective of ratemaking as referenced hereinabove.

Consequently, in summary, based upon the evidence in this proceeding, the Commission finds and concludes that a capital structure consisting of 50.27% common equity and 49.73% long-term debt (Utilities, Inc.'s actual capital structure as of September 30, 2013), a long-term debt cost rate of 6.60%, and a return on common equity of 9.75% are just and reasonable for CWSNC and should be approved.

Finally, based upon the foregoing findings of fact and the entire record in this proceeding, the Commission finds and concludes that the stipulated rates, the stipulated rate of return percentages, and all of the other provisions of the Amended Stipulation filed on January 10, 2014, which are incorporated herein by reference, with the exception of Sections 17-20 as discussed hereinbelow, are just and reasonable and should be approved.

Sewer Rates

In regard to sewer rates for the CLMS service area, the Stipulating Parties acknowledged that CLMS were designated for separate rate treatment in Docket No. W-354, Sub 314 (Sub 314), based, in part, on anticipated changes in the water systems serving those areas. The changes that were anticipated in Sub 314 did not occur, primarily because the water system was sold to Currituck County. As a result of the establishment of separate rates, the customers in CLMS experienced significantly higher percentage rate increases in Docket No. W-354, Sub 327 (Sub 327), than customers in other areas served by the Company. In recognition of these circumstances and events, the Stipulating Parties agreed that, for purposes of this proceeding and in light of changing circumstances, the current, system-specific sewer rates for the CLMS service area will remain unchanged from those established in Sub 327 and the Company's remaining revenue sewer requirement will be recovered through its uniform sewer rates for other systems. The Stipulating Parties agreed that in future rate case proceedings the issue of rate disparity will be reviewed again and appropriate consideration will be given to moving the CLMS service area toward uniform rates, in light of the facts and circumstances that exist at that time. The Commission finds this provision of the Amended Stipulation to be just and reasonable and should be approved.

With respect to monthly sewer rates for CWSNC's uniform rate sewer customers, Public Staff witness Casselberry testified that the Applicant provides flat rate service to all of its residential sewer customers and provides metered sewer utility service to all of its commercial sewer customers and Amherst Subdivision. However, pursuant to the Sub 324 Stipulation, the Company proposed in the present proceeding a monthly metered sewer rate for residential sewer customers who also receive metered water service from CWSNC.[1] As a result, the Stipulating Parties have agreed to a monthly metered sewer rate which includes a base facility charge (zero usage) of $18.68 and a usage charge, per 1,000 gallons, of $7.95, based on metered water usage. Based upon average monthly water consumption of 4,750, the average monthly metered residential sewer bill under the stipulated rates is $56.44.

Further, witness Casselberry testified that the Applicant's proposed metered rate for sewer service assumed that all of the residential customers have a 5/8 inch meter. Witness Casselberry stated that, based upon the billing data provided by the Company, she was unable to accurately determine the number of customers and the usage associated with those customers for meter sizes greater than 5/8 inch. As a result, in the present proceeding, witness Casselberry recommended one base rate for all residential customers receiving sewer service. On cross-examination by the Commission, witness Casselberry stated she was unable to estimate the number of meter sizes greater than 5/8 inch included in this proceeding but that "…most of them would be a one inch, but I don't think there's very many". The Public Staff recommended that CWSNC maintain accurate records for all metered sewer customers such that in the next general rate case proceeding residential customers with meter sizes greater than 5/8 inch will be charged the same rate as commercial customers with the same meter size. The Commission finds and concludes that such recommendation is reasonable and should be approved.

According to Casselberry Exhibit 19, approximately 6,233 residential sewer customers will be billed based upon a metered sewer rate as a result of the stipulated rates approved in this proceeding. Further, based upon Casselberry Late-Filed Exhibit 1, filed on December 4, 2013, there are approximately 2,656 residential sewer customers who receive their water source from a third-party provider who will continue to be charged a monthly flat sewer rate by the Applicant under the Amended Stipulation. The issue of a flat monthly sewer rate versus a monthly metered rate has been a concern expressed by numerous residential customers in the Company's past general rate case proceedings. As a result of the Sub 324 Stipulation, the Company has addressed this customer concern in the present proceeding for a large percentage of the residential customers.

With respect to the issue of a flat monthly residential sewer rate versus a monthly metered rate, the Commission is not convinced that metered residential sewer rates are in the best interest of CWSNC or its sewer customers. The Commission understands that pursuant to the Sub 324 Stipulation, the Company proposed in the present proceeding a monthly metered sewer rate for residential sewer customers who also receive metered water service from CWSNC. The Commission acknowledges that the terms of the Stipulations between the Parties in both the Sub 324 proceeding and in this proceeding resulted from extensive negotiations and compromise. Thus, the agreements reached in those stipulations do not necessarily reflect the respective Parties' beliefs as to the proper treatment or level of the matters cited within such stipulations. As a result, the Parties have agreed that the settlements made within such stipulations do not bind the Parties to the same positions in future proceedings, and the Parties reserve the right to take different positions in any future proceeding. Likewise, the Commission does not consider any portion of its orders that adopt stipulations to be precedent in future proceedings. Consequently, based upon the

[1] Pursuant to Section 24 of the Sub 324 Stipulation entered and filed on December 1, 2010, "[t]he Parties agree that CWS should develop a plan to meter sewer customers who are also metered water customers, and shall begin implementing this plan in its next general rate case."

Commission's concern that metered residential sewer rates may not be in the best interest of CWSNC or its sewer customers, the Commission may conclude in a CWSNC rate case proceeding in the future that the issue of a flat monthly residential sewer rate versus a monthly metered rate should be reevaluated.

In regard to wastewater operations, the Commission is of the opinion that a high percentage of the costs of wastewater treatment operations are fixed and that costs fluctuate little based on the volume of wastewater actually treated. Historically, the Commission has generally concluded that the justification for flat rates for residential sewer service is that most of the costs are fixed therefore customers should be responsible for their pro-rata share of the fixed costs irrespective of usage. The sewer capacity must be available to meet peak demand, so for customers to be entitled to service then they should pay their pro-rata share of the fixed costs. Additionally, the residential sewer usage where metered sewer rates are charged is measured at the water meter. Residents who use water for lawn and garden irrigation, for washing automobiles and other recreational usages, without an irrigation meter, for example, pay for sewer services they do not receive when charged metered sewer rates based on water meter readings. These are a number of the reasons the Commission has, with some consistency, declined requests in the past to approve metered residential sewer rates. While consumers who have low usage argue for metered sewer rates, consumers with high usage can now be expected to complain when billed on metered rates.

Concerning rate design, generally, it has been the practice of the Commission to design residential utility rates according to the ratio of fixed utility expenses to the utility expenses related to usage. For example, in general, water utilities have approximately a 40/60 fixed to variable expense ratio, whereas the ratio for sewer utilities is 80/20 to 90/10. Because the fixed expenses are such a large portion of the total expenses for wastewater operations, it has been customary to design a flat monthly rate for residential customers. In the current case, the proposed water base charge of $19.19 and proposed water usage charge of $5.62 will produce an average monthly residential bill of $45.89, based upon 4,750 gallons per month. The $19.19 base charge is 42% of the total bill, which is very close to the expected ratio for water operations. On the other hand, as previously discussed, the proposed sewer base charge of $18.68 and the proposed sewer usage charge of $7.95 will produce an average monthly residential bill of $56.44, based upon 4,750 gallons per month. The Commission observes that the $18.68 base charge is 33% of the total bill, which is much less than the expected ratio of 80% to 90% for wastewater operations. A rate design that would meet the expected ratio and produce the required revenue might be a base charge of $47.89 and a usage charge of $1.80. With such a rate design, CWSNC would likely recover its fixed expenses whether there was usage or not and the customers would be paying their fair share of the fixed expenses incurred by CWSNC for their benefit. Again, the Commission is mindful that the rates agreed to in the present proceeding are a part of a Stipulation between the Stipulating Parties and that the individual components of the Stipulation have no precedential value in future proceedings. Consequently, the Commission may conclude in a CWSNC rate case proceeding in the future that the sewer rate design issue should be reevaluated.

WSIC/SSIC

With respect to the Company's request for approval of a WSIC/SSIC mechanism in the present proceeding, on June 12, 2013, North Carolina Session Law 2013-106 (House Bill 710), An Act to Permit Water Utilities to Adjust Rates for Changes in Costs Based on Third-Party Rates and to Authorize the Utilities Commission to Approve Rate Adjustment Mechanism for Water and Sewer Utilities to Recover Costs for Water and Sewer System Improvements, was signed into law, having previously been ratified by the North Carolina General Assembly, resulting in newly enacted G.S. 62-133.12. This statute provides that the Commission may approve a rate adjustment mechanism in a general rate case proceeding to allow a water or sewer public utility to recover through a system improvement charge the incremental depreciation expense and capital costs associated with the utility's reasonable and prudently incurred investment in "eligible water and sewer system improvements".[1] Cumulative system improvement charges for a water or sewer utility may not exceed five percent of the total annual service revenues approved by the Commission in the water or sewer utility's last general rate case. G.S. 62-133.12 states that the Commission shall approve such rate adjustment mechanism only upon a finding that the mechanism is in the public interest.

CWSNC witness Neyzelman testified in support of the Company's request for approval, in the present proceeding, of a WSIC/SSIC mechanism. Witness Neyzelman submitted that there are several policy reasons for the passage of G.S. 62-133.12 which underlie the Company's request for approval of a WSIC/SSIC mechanism and that these reasons support a finding by the Commission that approval of a WSIC/SSIC mechanism in this rate case proceeding is in the public interest.

First, he stated that the legislature sought to encourage water and wastewater providers to replace aging infrastructure throughout the State. Witness Neyzelman maintained that this has many positive effects for residents in North Carolina, including increased water pressure, fewer main breaks, elimination of dead-end mains, and better management of inflow and infiltration for wastewater systems.

Second, witness Neyzelman testified that G.S. 62-133.12 specifically addresses secondary water quality standards which will incent water providers to address secondary water quality issues that may arise from the groundwater sources for various residential communities. He stated that CWSNC's North Carolina water sources throughout the State are principally groundwater. Witness Neyzelman explained that groundwater in this State often contains naturally occurring iron and manganese, which in some instances causes discolored, sediment-laden water. While such water can be, and is, provided in compliance with environmental regulations, many customers and water providers do not find this acceptable.

Third, witness Neyzelman submitted that a beneficial result of G.S. 62-133.12 was to minimize the impact of necessary rate increases by allowing for incremental adjustments, rather than the sharp rate increases that are characteristic of general rate cases. He contended that

[1] Pursuant to G.S. 62-133.12, "eligible water system improvements" or "eligible sewer system improvements" shall include only those improvements found necessary by the Commission to enable the water or sewer utility to provide safe, reliable, and efficient service in accordance with applicable water quality and effluent standards.

G.S. 62-133.12 would allow the Company to "smooth out" the impact of necessary rate increases and even to expand the time between general rate case filings. He maintained that this would reduce rate case expense and the carrying costs associated with extended periods of time between investment and recovery (regulatory lag).

For these reasons, witness Neyzelman requested that the Commission find and conclude that it was in the public interest in this general rate case proceeding to approve implementation of the Company's proposed WSIC/SSIC mechanism. In his testimony, witness Neyzelman described, for illustrative purposes, various projects CWSNC would potentially propose for rate recovery pursuant to the provisions of G.S. 62-133.12. He also provided the related estimated annual incremental depreciation expense and capital costs for each project.

Public Staff witness Fernald testified that G.S. 62-133.12(a) requires that the Commission approve a WSIC or SSIC rate adjustment mechanism only upon a finding that the mechanism is in the public interest. She stated that CWSNC has requested that the Commission find and conclude in this proceeding that it is in the public interest to approve a WSIC or SSIC mechanism for eligible investments in water and sewer improvements for immediate implementation by the Company. Witness Fernald testified that the Public Staff does not object to such a finding by the Commission provided that the rules, proposed by Aqua North Carolina, Inc., Utilities, Inc., and the Public Staff on November 8, 2013, in Docket No. W-100, Sub 54,[1] are adopted substantially as filed and the Company complies with those rules.

With respect to investments in water and sewer improvements, CWSNC witness Lashua testified that the Company does not currently obtain Commission approval prior to proceeding with its budgeted capital projects but rather exercises management discretion when it determines which specific projects to undertake. Witness Lashua commented that, currently, in general rate case proceedings the Company seeks recovery of amounts already invested knowing that the Public Staff and the Commission will scrutinize management's decisions to determine whether such investments were reasonable and prudent and will disallow any costs deemed to be unreasonable or imprudent. Witness Lashua stated that the Commission would still have its authority in a general rate case proceeding to disallow costs related to investments in water and sewer improvements recovered under the requested WSIC/SSIC mechanism that were subsequently determined by the Commission to be unreasonable or imprudent. Witness Lashua maintained that the requested WSIC/SSIC mechanism is simply accelerating the recovery of the capital investment which would incentivize the Company to invest more money at an earlier time.

On December 2, 2013, the Company filed its proposed three-year plan, as initial notice, contending this filing was consistent with the rules proposed in Docket No. W-100, Sub 54. The Company explained that the list of projects set forth in the proposed three-year plan was presented, not for the purpose of obtaining specific approval at this time, but rather, as a guide regarding potential projects necessary to support the initial approval by the Commission for the Company to implement a rate adjustment mechanism and to assist the Commission in making the statutorily required public interest finding in the present proceeding.

[1] The rulemaking proceeding to establish final rules related to the WSIC/SSIC mechanism is currently pending before the Commission.

Sections 17-20 of the Amended Stipulation provide the Stipulating Parties' agreements with respect to the Company's request for approval of a WSIC/SSIC mechanism in the present proceeding. In such sections, among other things, CWSNC, the Public Staff, and the CLCA acknowledged that the rulemaking establishing the procedures for implementing the rate adjustment mechanism allowed by G.S. 62-133.12 is pending before the Commission in Docket No. W-100, Sub 54, and that the final rules regarding such mechanism have not yet been approved.

The Stipulating Parties also agreed that the present general rate case proceeding was the appropriate forum for a decision by the Commission on the Company's request to implement a WSIC/SSIC mechanism and that approval of the WSIC/SSIC mechanism in this proceeding and the WSIC/SSIC Rulemaking should be coordinated. Therefore, the Stipulating Parties recommended that this docket be held open, or that the Commission adopt an alternative procedure in this docket, so that the Company can make the requisite filings and qualify for implementation of the system improvement charges under the rules ultimately to be adopted by the Commission in the WSIC/SSIC Rulemaking without having to make an additional rate case filing.

Further, the Stipulating Parties acknowledged that Recommended Rules R7-39 (n) and R10-26(n) in the WSIC/SSIC Rulemaking require that CWSNC file with the Commission the following reports within 45 days after the end of each calendar quarter, in a format as approved by the Commission: (1) a Quarterly Earnings Report; (2) a Quarterly Report on WSIC/SSIC Collections; and (3) a Quarterly Construction Status Report. In Section 19 of the Amended Stipulation, the Stipulating Parties provided the agreed-upon reporting format for each report.

The Commission agrees with the Stipulating Parties that the present rate case proceeding is the appropriate proceeding for a decision regarding the Company's request for a WSIC/SSIC mechanism. The Commission is of the opinion that the General Assembly has recognized a need in North Carolina to incentivize water and sewer utilities to invest in needed infrastructure improvements. The Commission believes that the primary purpose for the enactment of G.S. 62-133.12 is to encourage and accelerate investment in needed water and sewer infrastructure by means of a mechanism which will alleviate the effects of regulatory lag by allowing for earlier recovery of some portion, not to exceed 5% of approved service revenues, of the incremental depreciation and capital costs associated with eligible investments made between general rate case proceedings. In accordance with G.S. 62-133.12, eligible water system and sewer system improvements would be installed, for example, to comply with primary drinking water standards, to implement solutions to wastewater problems, and to comply with State and federal law and regulations. Further, G.S. 62-133.12 allows, upon the Commission's specific direction, for the utility to implement solutions to comply with otherwise non-mandatory secondary drinking water standards.

The Commission believes that CWSNC would be incentivized and encouraged to accelerate its investment in water and sewer infrastructure improvements to comply with applicable water quality and effluent standards, including secondary water quality standards, if authorized to utilize a WSIC/SSIC mechanism to alleviate the effects of regulatory lag. The Commission is of the opinion, and consequently, finds and concludes that it is in the public interest to authorize CWSNC to utilize a WSIC/SSIC mechanism to recover the incremental depreciation expense and capital costs associated with the Company's reasonable and prudently incurred eligible investment in water and sewer infrastructure projects completed and placed in service between general rate case proceedings.

It is the opinion of the Commission that providing an incentive to the Company to undertake more extensive improvements to address secondary water quality issues in those individual subdivision service areas which have, for example, iron and manganese concentration levels that exceed federal and state standards which have not been sufficiently remedied on a sustained basis by past treatment methods, benefits the Company's customers who are paying for water they feel they cannot ingest or that damages their property due to unresolved secondary water quality issues. Moreover, the recovery mechanism is of further benefit to customers because it will be available to fund projects to address problematic systemic secondary water quality issues should the Commission direct the Company to undertake them in individual subdivision service areas, even though such projects may not be specifically required by federal and/or state standards and would not be high priority to the Company absent the direction of the Commission. The Commission believes that some secondary water quality improvement projects generally may have been given lower priority in the past by water utilities because limited available capital budget funds are spent first on primary water quality improvements. The availability of the WSIC recovery mechanism should, to customer benefit, provide the Company with increased incentive and wherewithal to address secondary water quality issues on a sustained basis and sooner than it would otherwise be able.

Also, to the extent that necessary investments would result in rate increases at some point in time irrespective of the mechanism, the public will benefit from the rate-smoothing effects of more gradual increases made possible by recovery through a WSIC/SSIC surcharge. Furthermore, if the ability to increase rates to recover certain costs between general rate cases actually results in fewer or less frequent rate cases as claimed by the Company, ratepayers would benefit from lower rates because the Company's recoverable expenses would be reduced by the elimination of the substantial costs associated with preparation and litigation of a rate case.

With respect to testimony by public witnesses regarding the WSIC/SSIC mechanism, some customers expressed concerns: (1) about "double-dipping" if a surcharge was approved and then a rate of return adjustment approximately every two years was also approved; (2) that the Commission would have to ensure that the WSIC/SSIC improvements that are occurring are not simply repair expenses but are system improvements that are in the public interest; (3) that the capital improvements to be recovered through the surcharge have already been recovered through depreciation expense; and (4) that there would be no way for the Commission to disapprove an improvement in the future after the money has been collected from the customers. The Commission finds that while an approved mechanism will allow cost recovery resulting in limited or capped rate increases between general rate cases, WSIC/SSIC surcharges are subject to Commission review and scrutiny for reasonableness and prudency in general rate case proceedings as has been the case for investments and expenses prior to the enactment of G.S. 62-133.12. Consequently, the Commission will still have its authority in a general rate case proceeding to disallow costs related to investments in water and sewer improvements recovered under the WSIC/SSIC mechanism that were subsequently determined to be unreasonable or imprudent.

Further, prior to the initiation of each surcharge, the Company must obtain approval from the Commission. As a result, the capital improvements to be included in the requested surcharge will be scrutinized by both the Public Staff and the Commission to determine whether they are eligible for recovery through the WSIC/SSIC mechanism, pursuant to G.S. 62-133.12, before customers are actually charged under the mechanism. The use of such a mechanism will not result in “double-dipping”. It is a means for the Company to accelerate the recovery of certain capital investments which will incentivize the Company to invest more money at an earlier time for the benefit of customers both in the short and long term. The procedures adopted by the Commission for implementation of the WSIC/SSIC mechanism require, among other things, periodic reporting by the Company in formats prescribed by the Commission; an audit and annual report to the Commission by the Public Staff; and a true-up mechanism which provides for the refund to customers of over-collections, if any, with interest.

In regard to customer notice, the Commission’s August 19, 2013 Order Scheduling Hearings and Requiring Customer Notice required CWSNC to notify customers that it was requesting Commission authorization, pursuant to G.S. 62-133.12, to implement a water and sewer charge mechanism to recover between this general rate case and the next one the costs associated with investment in certain completed, eligible projects for system or water quality improvements. On September 6, 2013, the Company filed its Certificate of Service certifying that notice had been provided to customers in accordance with the terms and conditions specified in the Commission’s August 19, 2013 Order. Such notice stated that any cumulative system improvement charges recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding.

In consideration of the foregoing and the entire record in this docket, the Commission is of the opinion, and so finds and concludes, that the Company’s request for approval of a WSIC/SSIC mechanism in the context of this proceeding should be approved. The Commission, therefore, finds and concludes that good cause exists to adopt the alternative procedures set forth in Appendices C and D of this Order which are expressly incorporated herein.[1] Such procedures include, among other things, the approval procedure for the initiation of the charges; computation guidelines with respect to the WSIC/SSIC revenue requirements; detailed reporting requirements; and audit, reconciliation, and adjustment procedures. Further, the alternative procedures establish that CWSNC’s WSIC and SSIC period will be the 12 months ended March 31. The Company may file a request for a WSIC/SSIC adjustment no more frequently than semiannually.

The Commission believes the procedures provided in Appendices C and D should provide ample regulatory oversight of the WSIC/SSIC mechanism for the protection of the customers. Further, the Commission acknowledges that, all infrastructure improvements will be reviewed by the Public Staff and the Commission to determine whether they are eligible for cost recovery through the WSIC/SSIC mechanism and will be reviewed again for prudency and reasonableness in the Company’s next general rate case proceeding. The review process is even more stringent for secondary water quality projects to be recovered through the WSIC mechanism as they require initial, specific approval by the Commission pursuant to G.S. 62-133.12.

[1] The Nags Head sewer operations are not yet eligible for SSIC as the Nags Head service area was not included in this general rate case proceeding.

As a result of the alternative procedures approved herein, CWSNC can make the requisite filings and qualify for implementation of the WSIC and SSIC mechanism without having to make an additional rate case filing subsequent to the adoption of final rules in Docket No. W-100, Sub 54. Appendices C and D provide, among other things, that CWSNC shall file the following reports with the Commission within 45 days after the end of each calendar quarter: (1) the Quarterly Earnings Report; (2) the Quarterly Report on WSIC/SSIC Collections; and (3) the Quarterly Construction Status Report. Further, such reporting requirements shall be provided in the report formats agreed to by the Stipulating Parties as set forth in Section 19 of the Amended Stipulation.

In light of the Commission's decision to adopt the alternative procedures provided in Appendices C and D of this Order with respect to the WSIC/SSIC mechanism, the Commission holds that Sections 17-20 of the Amended Stipulation are now moot and thus will not be specifically approved. Because these sections of the Amended Stipulation are moot, the Commission does not believe that the Stipulating Parties' agreement contained in Section 39 that "[n]o portion of this Stipulation will be binding on the Stipulating Parties unless the entire Stipulation is accepted by the Commission" is implicated or should release the parties from their agreement and stipulation.

The alternative procedures provided in Appendices C and D of this Order, and adopted herein, require that CWSNC file a request with the Commission for authority to impose the WSIC/SSIC mechanism once the eligible system improvements are in service. The effective date of the WSIC/SSIC would be no less than 60 days after filing the request. Such request must also be filed with the Public Staff. Other parties interested in receiving notice of CWSNC's request to impose the WSIC/SSIC mechanism may subscribe to the Commission's electronic notification system, for Docket No. W-354, Sub 336A, through the Commission's website at www.ncuc.net.

Prior to the requested effective date of the mechanism, the Public Staff will present the Company's request for Commission consideration at a regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed WSIC/SSIC. The Commission is of the opinion and therefore, so finds and concludes, that the foregoing procedure will provide adequate notice to interested parties with respect to the proposed imposition of the WSIC/SSIC mechanism by CWSNC between general rate case proceedings.

As previously discussed, G.S. 62-133.12 requires that the Commission specifically approve those projects that address secondary water quality standards. The Commission is concerned about water quality issues that arise as a result of the regulated water utilities failing to meet certain secondary water quality standards. For example, the Commission understands that while discolored, sediment-laden water can be, and is, provided in compliance with environmental regulations, many customers do not find this acceptable and consequently do not consume the water or are unable to use the water for basic, routine functions due to this unaddressed secondary water quality issue. Additionally, the Commission recognizes that damage of customer property due to unaddressed secondary water quality issues, such as staining of toilets and fixtures, buildup of sediment in hot water heaters, deterioration of household plumbing parts, and stained laundry items results in additional expense incurred by customers because such property has to be replaced more frequently than would otherwise occur if such secondary water quality concerns were not present.

The Commission urges the Company to be mindful of these types of customer concerns as they arise between this general rate case and the next one and to include proposals for adequate remedies to alleviate such secondary water quality concerns for consideration by the Commission in its future requests for WSIC recovery. The Commission believes that the Public Staff and the Company should work together to develop and implement a plan to identify and respond to secondary water quality concerns that occur in significant numbers in individual subdivision service areas. At a minimum, this plan should require the Public Staff and the Company to file a written report with the Commission on June 1 and December 1 each year in which the WSIC is in effect on secondary water quality concerns that are affecting its customers. If a particular secondary water quality concern has affected or is affecting 10 percent of the customers in an individual subdivision service area or 25 billing customers, whichever is less, the written plan should detail the customers affected and the estimated expenditures necessary to eradicate the secondary water quality issues through the use of projects that are eligible for recovery through the WSIC. The written report should also contain a recommendation as to whether the Commission should order the Company to pursue the corrective action and/or an underlying reason(s) why the action should or should not be undertaken. If there are no secondary water quality issues or if the secondary water quality issues are below the stated threshold, the Company and the Public shall so inform the Commission. Finally, secondary water quality issues which have been resolved by the Company without the assistance or expectation of assistance of the WSIC need not be included in the written report.

IT IS, THEREFORE, ORDERED as follows:

1. That the Amended Stipulation between CWSNC, the Public Staff, and the Corolla Light Community Association, Inc., with the exception of Sections 17-20, incorporated by reference herein, is hereby approved.

2. That the Schedules of Rates, attached hereto as Appendices A-1 and A-2, are hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

3. That the attached Schedules of Rates are hereby authorized to become effective for service rendered on and after the date of issuance of this Order.

4. That the Notices to Customers, attached hereto as Appendices B-1 and B-2, shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant service area, respectively, in conjunction with the next regularly scheduled billing process.

5. That CWSNC shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notices to Customers are mailed or hand delivered to customers.

6. That neither the Amended Stipulation entered into and filed on January 10, 2014, nor the parts of this Order pertaining to the contents of that agreement shall be cited or treated as precedent in future proceedings.

7. That CWSNC shall install all meters and fully meter the unmetered systems in Powder Horn, Misty Mountain, Crystal Mountain, Watauga Vista, High Meadows, Ski Country (a part of Sugar Mountain), and Mt. Mitchell, before the evidentiary hearing in its next general rate case proceeding. CWSNC shall immediately switch customers to metered rates as soon as each system is fully metered.

8. That CWSNC shall modify its billing system such that CWSNC has the capability to generate reports that reflect the actual number of customers each month (not the number of bills produced each month) or shall change its policy concerning billing cycles such that customers shall be billed only once per month.

9. That CWSNC shall include the following in its NCUC Form W-1 filing in its next general rate case proceeding: (a) an individual spreadsheet for each service area, which shows the number of actual customers served for each meter type, and the actual usage for each meter type for each month for the 12-month test period specified in its application and (b) a spreadsheet summarizing the total number of active customers and total usage for each billing type for each month for the 12-month test period specified in the application.

10. That CWSNC shall maintain accurate records for all metered sewer customers such that in the next general rate case proceeding residential customers with meter sizes greater than 5/8 inch will be charged the same rate as commercial customers with the same meter size.

11. That in future general rate case proceedings, the issue of rate disparity shall be reviewed by CWSNC, the Public Staff, and any other interested party and appropriate consideration shall be given to moving the CLMS service area toward uniform rates in light of the facts and circumstances that exist at that time.

12. That CWSNC shall work with the Public Staff on the appropriate mechanisms for effectuating the changes mandated by House Bill 998, effective July 1, 2014 and January 1, 2015, as stipulated, and shall file notice of the proposed rate reductions with the Commission by June 1, 2014 and December 1, 2014, as stipulated.

13. That CWSNC's request to utilize a WSIC/SSIC mechanism pursuant to G.S. 62-133.12 to recover certain incremental costs related to eligible investment in water and sewer infrastructure projects completed and placed in service between general rate case proceedings is in the public interest and is hereby approved.

14. That CWSNC shall utilize the alternative procedures set forth in Appendices C and D, attached hereto, and shall make the requisite filings in order to qualify for implementation of the WSIC/SSIC without having to make an additional rate filing subsequent to the adoption of final rules in Docket No. W-100, Sub 54.

15. That the Public Staff and the Company shall work together to develop and implement a plan to identify and respond to secondary water quality concerns that occur in significant numbers in individual subdivision service areas. At a minimum, the Public Staff and the Company are required to file a written report with the Commission on June 1 and December 1 each year in which the WSIC is in effect on secondary quality concerns that are affecting its customers. If a particular secondary water quality concern has affected or is affecting 10 percent of the customers in an individual subdivision service area or 25 billing customers, whichever is less, the customers affected and the estimated expenditures that are necessary to eradicate the secondary water quality issues through the use of projects that are eligible for recovery through the WSIC shall be detailed in the written report. The written report shall also contain a recommendation as to whether the Commission should order the Company to pursue the corrective action and/or an underlying reason why the action should or should not be undertaken. If there are no secondary water issues or if the secondary water quality issues are below the10%/25 threshold previously set forth, the Company and the Public shall so inform the Commission, but they need not report secondary water quality issues resolved by the Company without the assistance or expectation of assistance of the WSIC.

ISSUED BY ORDER OF THE COMMISSION.
This the _10th_ day of _March, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX A-1
PAGE 1 OF 7

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service in

ALL ITS SERVICE AREAS IN NORTH CAROLINA
(excluding Corolla Light, Monteray Shores, Nags Head, and Linville Ridge)

WATER RATES AND CHARGES

WATER AND SEWER – RATE INCREASE

MONTHLY METERED SERVICE (Residential and Commercial):

Base Facilities Charge
(based on meter size with zero usage)

< 1” meter	$ 19.19
1” meter	$ 47.98
1½” meter	$ 95.95
2” meter	$ 153.52
3” meter	$ 287.85
4” meter	$ 479.75
6” meter	$ 959.50

USAGE CHARGE:

A. Treated Water, per 1,000 gallons — $ 5.62

B. Untreated Water, per 1,000 gallons
(Brandywine Bay Irrigation Water) — $ 3.75

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

MONTHLY FLAT RATE SERVICE: $ 36.06

AVAILABILITY RATES (semi-annual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County — $ 22.50

METER TESTING FEE: 1/ — $ 20.00

NEW WATER CUSTOMER CHARGE: $ 27.00

RECONNECTION CHARGES: 2/

If water service is cut off by utility for good cause	$ 27.00
If water service is disconnected at customer’s request	$ 27.00

MANAGEMENT FEE (in the following subdivision only):

Wolf Laurel	$ 150.00

OVERSIZING FEE (in the following subdivision only):

Winghurst	$ 400.00

METER FEE:

For < 1”meters	$ 50.00
For meters 1” or larger	Actual Cost

IRRIGATION METER INSTALLATION: Actual Cost

UNIFORM CONNECTION FEES: [3/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE (Single Family Equivalent)	$ 100.00
Plant Modification Fee (PMF), per SFE	$ 400.00

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amherst	$ 250.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Blue Mountain at Wolf Laurel	$ 925.00	$ 0.00
Buffalo Creek, Phase I, II, III, IV	$ 825.00	$ 0.00
Carolina Forest	$ 0.00	$ 0.00
Chapel Hills	$ 150.00	$ 400.00
Eagle Crossing	$ 0.00	$ 0.00
Forest Brook/Old Lamp Place	$ 0.00	$ 0.00
Harbour	$ 75.00	$ 0.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Lemmond Acres	$ 0.00	$ 0.00
Monterrey (Monterrey, LLC)	$ 0.00	$ 0.00
Quail Ridge	$ 750.00	$ 0.00

Queens Harbour/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Riverwood, Phase 6E (Johnston County)	$ 825.00	$ 0.00
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$ 500.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

APPENDIX A-1
PAGE 4 OF 7

SEWER RATES AND CHARGES

MONTHLY METERED SERVICE:

A.	Base Facility Charge (based on meter size with zero usage)	
	Residential	$ 18.68
	Commercial	
	<1" meter	$ 18.68
	1" meter	$ 46.70
	1½" Meter	$ 93.40
	2" meter	$ 149.44
	3" meter	$ 280.20
	4" meter	$ 467.00
	6" meter	$ 934.00
B.	Usage Charge, per 1,000 gallons (based on metered water usage)	$ 7.95
C.	Sewer customers who do not receive water service from the Company (per SFE or Single Family Equivalent)	$ 56.45

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

MONTHLY FLAT RATE SERVICE:		$ 56.45
MONTHLY COLLECTION SERVICE ONLY: 4/ (When sewage is collected by utility and transferred to another entity for treatment)		
A.	Single Family Residence	$ 20.33
B.	Commercial/SFE	$ 20.33

APPENDIX A-1
PAGE 5 OF 7

MT. CARMEL SUBDIVISION SERVICE AREA:
(Based on metered water usage)

Monthly Base Facility Charge	$ 7.58
Usage Charge, per 1,000 gallons	$ 5.45

REGALWOOD AND WHITE OAK ESTATES SUBDIVISION SERVICE AREA:

Monthly Flat Rate Sewer Service	
Residential Service	$ 56.45
White Oak High School	$1,751.85
Child Castle Daycare	$ 217.80
Pantry	$ 116.00

NEW SEWER CUSTOMER CHARGE: 5/	$ 22.00
RECONNECTION CHARGE: 6/	
If sewer service is cut off by utility for good cause	Actual Cost

CAROLINA PINES SUBDIVISION CONNECTION FEES (sewer only): 3/

Residential	$1,350.00 per unit (Including Single Family Homes, Condominiums, Apartments, and Mobile Homes)

Hotels	$750.00 per unit
Nonresidential	$3.57 per gallon of daily design of discharge or $900.00 per unit, whichever is greater

UNIFORM CONNECTION FEES: [3/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved by the North Carolina Utilities Commission are as follows:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amber Acres North (Phases II & IV)	$ 815.00	$ 0.00
Ashley Hills	$ 0.00	$ 0.00
Amherst	$ 500.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Brandywine Bay	$ 100.00	$1,456.00
Camp Morehead by the Sea	$ 100.00	$1,456.00
Hammock Place	$ 100.00	$1,456.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 30.00	$ 0.00
Huntwick	$ 0.00	$ 0.00
Independent/HembyAcres/Beacon Hills (Griffin Bldrs.)	$ 0.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Kynwood	$ 0.00	$ 0.00
Mt. Carmel/Section 5A	$ 500.00	$ 0.00
Queens Harbor/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Steeplechase (Spartabrook)	$ 0.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Willowbrook (Phase 3)	$ 0.00	$ 0.00

Winston Pointe, Phase 1A	$2,000.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

APPENDIX A-1
PAGE 7 OF 7

MISCELLANEOUS UTILITY MATTERS

BILLS DUE:	On billing date
BILLS PAST DUE:	21 days after billing date
BILLING FREQUENCY:	Bills shall be rendered monthly in all service areas, except for Mt. Carmel which will be billed bimonthly, and the availability charges in Carolina Forest and Woodrun Subdivisions which will be billed semiannually.
FINANCE CHARGE FOR LATE PAYMENT:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.
CHARGES FOR PROCESSING NSF CHECKS:	$25.00

NOTES:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

2/ Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

3/ These fees are only applicable one time, when the unit is initially connected to the system.

4/ The utility shall charge for sewage treatment service provided by the other entity; the rate charged by the other entity will be billed to Carolina Water Service's affected customers on a pro rata basis, without markup.

5/ These charges shall be waived if sewer customer is also a water customer within the same service area.

6/ The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 336, on this the _10th_day of _March_, 2014.

APPENDIX A-2
PAGE 1 OF 2

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing sewer utility service in

COROLLA LIGHT AND MONTERAY SHORES SERVICE AREA

SEWER RATES AND CHARGES

MONTHLY METERED SERVICE (Residential and Commercial):

A. Base Facility Charge (based on meter size with zero usage)

<1” meter	$ 55.54
1” meter	$ 138.85
1½” Meter	$ 277.70
2” meter	$ 444.32
3” meter	$ 833.10
4” meter	$1,388.50
6” meter	$2,777.00

B. Usage Charge, per 1,000 gallons (based on metered water usage) $ 7.06

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

WATER AND SEWER – RATE INCREASE

NEW SEWER CUSTOMER CHARGE: $ 22.00

RECONNECTION CHARGE: [1/]

If sewer service is cut off by utility for good cause — Actual Cost

UNIFORM CONNECTION FEES: [2/]

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission:

Connection Charge (CC), per Single Family Equivalent (SFE)	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved by the North Carolina Utilities Commission are as follows:

Subdivision	CC	PMF
Corolla Light	$ 700.00	$ 0.00
Monteray Shores	$ 700.00	$ 0.00
Monteray Shores (Degabrielle Builders)	$ 0.00	$ 0.00

MISCELLANEOUS UTILITY MATTERS

BILLS DUE:	On billing date
BILLS PAST DUE:	21 days after billing date
BILLING FREQUENCY:	Bills shall be rendered monthly in all service areas.
FINANCE CHARGE FOR LATE PAYMENT:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.
CHARGES FOR PROCESSING NSF CHECKS:	$25.00

NOTES:

1/ The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice.

Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

2/ These fees are only applicable one time, when the unit is initially connected to the system.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 336, on this the _10th_day of _March_, 2014.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B-1
PAGE 1 OF 4

DOCKET NO. W-354, SUB 336

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Services, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina, Excluding Nags Head	)))))))	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina to charge increased rates for water and sewer utility service in all of its service areas in North Carolina (excluding Corolla Light, Monteray Shores, Linville Ridge and Nags Head). The new approved rates are as follows:

WATER RATES AND CHARGES

MONTHLY METERED SERVICE (Residential and Commercial):

Base Facilities Charges (based on meter size with zero usage)

< 1" meter	$ 19.19
1" meter	$ 47.98
1½" meter	$ 95.95
2" meter	$153.52
3" meter	$287.85
4" meter	$479.75
6" meter	$959.50

<u>USAGE CHARGE</u>:

A.	Treated Water, per 1,000 gallons	$ 5.62
B.	Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 3.75

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

<u>MONTHLY FLAT RATE SERVICE</u>: $ 36.06

<u>AVAILABILITY RATES (semi-annual)</u>:

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County $ 22.50

SEWER RATES AND CHARGES

<u>MONTHLY METERED SERVICE</u>:

A. Base Facility Charges (based on meter size with zero usage)

Residential	$ 18.68
Commercial	
<1" meter	$ 18.68
1" meter	$ 46.70
1½" meter	$ 93.40
2" meter	$ 149.44
3" meter	$ 280.20
4" meter	$ 467.00

	6" meter	$ 934.00
B.	Usage Charge, per 1,000 gallons (based on metered water usage)	$ 7.95
C.	Sewer Customers who do not receive water service from the Company (per SFE or Single Family Equivalent)	$ 56.45

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

APPENDIX B-1
PAGE 3 OF 4

MONTHLY FLAT RATE SERVICE: $ 56.45

MONTHLY COLLECTION SERVICE ONLY:
(When sewage is collected by utility and transferred to another entity for treatment)

A.	Single Family Residence	$ 20.33
B.	Commercial/SFE	$ 20.33

MT. CARMEL SUBDIVISION SERVICE AREA:

Monthly Base Facility Charge	$ 7.58
Usage Charge, per 1,000 gallons (based on metered water usage)	$ 5.45

REGALWOOD AND WHITE OAK ESTATES SUBDIVISION SERVICE AREAS:

Monthly Flat Rate Sewer Service:

Residential Service	$ 56.45
White Oak High School	$1,751.85
Child Castle Daycare	$ 217.80
Pantry	$ 116.00

APPENDIX B-1
PAGE 4 OF 4

RATE ADJUSTMENT MECHANISM:

The Commission has approved the Company's request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) mechanism designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-354 Sub 336".

ISSUED BY ORDER OF THE COMMISSION.
This the _10th_ day of _March, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B-2
PAGE 1 OF 2

DOCKET NO. W-354, SUB 336

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Water Services, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina, Excluding Nags Head	))))))	**NOTICE TO CUSTOMERS**

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina to charge the following rates for sewer utility service in its Corolla Light and Monteray Shores service area in North Carolina. These are the same rates that were in effect prior to the completion of this general rate case proceeding. The rates for customers in the Corolla Light and Monteray Shores service area were not changed (increased or decreased) in any manner.

MONTHLY METERED SERVICE (Residential and Commercial):

A. Base Facility Charges (based on meter size with zero usage)

<1” meter	$ 55.54
1" meter	$ 138.85
1½” meter	$ 277.70
2" meter	$ 444.32
3" meter	$ 833.10
4" meter	$1,388.50
6" meter	$2,777.00

B. Usage Charge, per 1,000 gallons

(based on metered water usage)	$ 7.06

APPENDIX B-2
PAGE 2 OF 2

Commercial customers, including condominiums or other property owner associations who bill their members directly, shall have a separate account set up for each meter and each meter shall be billed separately based on the size of the meter and usage associated with the meter.

RATE ADJUSTMENT MECHANISM:

The Commission has approved the Company’s request, pursuant to G.S. 62-133.12, for authority to implement a water and sewer system improvement charge (WSIC/SSIC) mechanism designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for system or water quality improvement. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanism is contained in the Commission’s Order and can be accessed from the Commission’s website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number “W-354 Sub 336”.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of March, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Chief Clerk

APPENDIX C
PAGE 1 OF 5

Water System Improvement Charge Procedure

Appendix C provides the procedure for the approval and administration of a rate adjustment mechanism pursuant to G.S. 62-133.12 to allow CWSNC to recover the incremental depreciation expense and capital costs related to the Company's reasonable and prudently incurred investment in eligible water system improvements.

(A) Definitions.–As used in Appendix C:

(1) "Capital costs" means the pretax return on costs permitted to be capitalized pursuant to the NARUC Uniform System of Accounts, net of accumulated depreciation and accumulated deferred income taxes, using the current federal and state income tax rates and the Company's capital structure, cost of long-term debt, and return on equity approved in the Company's most recent general rate case.

(2) "Depreciation expense" means the annual depreciation accrual rates employed in the Company's most recent general rate case for the plant accounts in which the cost of each eligible water system improvement is recorded applied to the cost of eligible water system improvements.

(3) "Eligible water system improvements" means the improvements set forth in G.S. 62-133.12(c) and shall include only those improvements found necessary by the Commission to provide safe, reliable, and efficient service in accordance with applicable water quality standards.

(4) "Incremental depreciation expense and capital costs" means depreciation expense and capital costs that have been incurred since the Company's most recent rate case and have not been included in the Company's cost of service for ratemaking purposes.

(5) "Water System Improvement Charge or WSIC" means an adjustment to customer bills that allows the Company to recover the WSIC Revenue Requirement.

(6) "WSIC Revenue Requirement" means the annual revenue required to allow the Company to recover the annual incremental depreciation expense and capital costs of eligible water system improvements.

(7) "WSIC Period" means the 12-month period ended March 31 for CWSNC.

(8) "WSIC mechanism" means a rate adjustment mechanism approved by the Commission in a general rate case pursuant to G.S. 62-133.12.

(B) Initiation of Charge.–Once eligible water system improvements are in service, the Company may file a request with the Commission for authority to impose the water system improvement charge pursuant to the mechanism, to be effective no less than 60 days after filing the request. This request shall also be filed with the Public Staff.[1] Prior to the effective date, the Public Staff shall schedule the request for Commission consideration at the regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed water system improvement charge. The Public Staff shall formally notify the Commission at least 15 days in advance of the date that the request shall be scheduled for Commission consideration at the regularly scheduled staff conference.

(C) Computation of the WSIC Revenue Requirement.–The WSIC Revenue Requirement shall be computed for each WSIC Period as follows:

Eligible water system improvements	$X,XXX,XXX
Less: Accumulated depreciation	X,XXX,XXX
Less: Accumulated deferred income taxes	X,XXX,XXX
Net plant investment	$X,XXX,XXX
Pre-tax rate of return	X.XX%
Capital costs	$X,XXX,XXX
Plus: Depreciation expense	XXX,XXX
Subtotal, excluding regulatory fee	$X,XXX,XXX
Regulatory fee gross-up factor	XXXX
Total	$X,XXX,XXX

(D) Computation of the Water System Improvement Charge.

(1) The WSIC shall be expressed as a percentage carried to two decimal places and shall be applied to the total utility bill of each customer under the Company's applicable service rates and charges.

(2) The WSIC shall be computed by dividing the annual WSIC Revenue Requirement by the projected revenues of the Company during the 12-month period following implementation of the charge.

(E) Semi-Annual Adjustments. – The Company may file a request for a WSIC adjustment no more frequently than semiannually.

[1] Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system, for docket number "W-354 Sub 336A", through the Commission's website at www.ncuc.net.

APPENDIX C
PAGE 3 OF 5

(1) The request shall include the computation and supporting data for the adjustment.

(2) Cumulative WSIC Revenue Requirements may not exceed 5.0% of the total annual service revenues approved in this general rate proceeding.

(3) The procedural requirements set forth in subsection (B) of this Appendix shall apply to requests for semi-annual adjustments.

(F) Experience Modification Factor.–The WSIC shall be modified through the use of an experience modification factor (EMF) that reflects the difference between the WSIC Revenue Requirement and the revenues that were actually realized under the WSIC during the WSIC Period. The EMF shall remain in effect for a 12-month period. Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred costs of the Company for eligible water system improvements to be refunded to the Company's customers through operation of the EMF shall include an amount of interest at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(G) Water System Improvement Charge Reset.–The WSIC shall be reset at zero as of the effective date of new base rates established in the Company's general rate case. Thereafter, only the incremental depreciation expense and capital costs of new eligible water system improvements that have not previously been reflected in the Company's rates shall be recovered through the WSIC.

(H) Audit and Reconciliation.–The WSIC shall be subject to the following:

(1) Within 60 days following the end of each WSIC Period, the Company shall file a report, in a format prescribed by the Commission, reconciling its actual eligible water system improvement costs, actual WSIC revenues, and EMF computation; and

(2) The Public Staff shall audit the Company's actual eligible water system improvement costs, actual WSIC revenues, and EMF computation, and shall file a report on its audit no later than four months after the end of the WSIC Period of the Company.

(I) Ongoing Three-Year Plan.–Within 60 days following the end of each WSIC Period, the Company shall file an updated three-year plan containing the following information:

APPENDIX C
PAGE 4 OF 5

a. A detailed description of all proposed eligible water system improvements expected to be completed in the WSIC Period and an estimate of the cost of the improvements and dates when the improvements will be placed into service; and

b. A brief description of the proposed eligible water system improvements, estimated costs, and completion dates for improvements that the Company plans to complete during the two years following the WSIC Period.

c. Any other information required by the Commission.

(J) Quarterly Filings with the Commission.–Within 45 days after the end of each calendar quarter, the Company shall file the following reports:

(1) A quarterly earnings report consisting of the following:

(a) A balance sheet and income statement for the calendar quarter and calendar year to date for CWSNC;

(b) A statement of the per books net operating income for the calendar quarter and calendar year to date for each rate division (CWSNC uniform water, CWSNC uniform sewer, CLMS sewer operations, and Nags Head sewer operations) based on North Carolina ratemaking and in the same format as the Per Books column on Schedule B of the Company's general rate case application;

(c) A statement of rate base at the end of the calendar quarter for each rate division based on North Carolina ratemaking in the same format as the Per Books column on Schedule C of the Company's general rate case application; and

(d) The number of customers and gallons sold for each month of the calendar quarter for each rate division by rate type (meter size, flat rate, etc.).

(2) A quarterly report of WSIC collections from customers consisting of amounts collected for the quarter by rate division and rate type; and

(3) A construction status report which includes by rate division the following information for each eligible system improvement project: (a) the costs incurred during the quarter; (b) the cumulative amount incurred; (c) the estimated total cost for the project; (d) the estimated completion date; and (e) the actual completion date.

APPENDIX C
PAGE 5 OF 5

(K) Elimination or Modification of WSIC Mechanism.—After notice to the Company and opportunity to be heard, the Commission may eliminate or modify any previously authorized WSIC mechanism upon a finding that it is not in the public interest.

(L) Burden of Proof.–The burden of proof as to whether a WSIC mechanism is in the public interest, the correctness and reasonableness of any WSIC, and whether the investment in the water system improvements was reasonable and prudently incurred shall be on the Company.

APPENDIX D
PAGE 1 OF 5

Sewer System Improvement Charge Procedure

Appendix D provides the procedure for the approval and administration of a rate adjustment mechanism pursuant to G.S. 62-133.12 to allow CWSNC[1]to recover the incremental depreciation expense and capital costs related to the Company's reasonable and prudently incurred investment in eligible sewer system improvements.

(A) Definitions.–As used in Appendix D:

(1) "Capital costs" means the pretax return on costs permitted to be capitalized pursuant to the NARUC Uniform System of Accounts, net of accumulated depreciation and accumulated deferred income taxes, using the current federal and state income tax rates and the Company's capital structure, cost of long-term debt, and return on equity approved in the Company's most recent general rate case.

(2) Depreciation expense" means the annual depreciation accrual rates employed in the Company's most recent general rate case for the plant accounts in which the cost of each eligible sewer system improvement is recorded applied to the cost of eligible sewer system improvements.

(3) "Eligible sewer system improvements" means the improvements set forth in G.S. 62-133.12(d) and shall include only those improvements found necessary by the Commission to provide safe, reliable, and efficient service in accordance with applicable effluent standards.

[1] The Nags Head sewer operations are not yet eligible for SSIC as the Nags Head service area was not included in this general rate case proceeding.

(4) "Incremental depreciation expense and capital costs" means depreciation expense and capital costs that have been incurred since the Company's most recent rate case and have not been included in the Company's cost of service for ratemaking purposes.

(5) "Sewer System Improvement Charge or SSIC" means an adjustment to customer bills that allows a utility to recover the SSIC Revenue Requirement.

(6) "SSIC Revenue Requirement" means the annual revenue required to allow the Company to recover the annual incremental depreciation expense and capital costs of eligible sewer system improvements.

(7) "SSIC Period" means the 12-month period ended March 31 for CWSNC.[1]

(8) "SSIC mechanism" means a rate adjustment mechanism approved by the Commission in a general rate case pursuant to G.S. 62-133.12.

(B) Initiation of Charge.–Once a SSIC mechanism is approved and eligible sewer system improvements are in service, the Company may file a request with the Commission for authority to impose the sewer system improvement charge pursuant to the mechanism, to be effective no less than 60 days after filing the request. The Company shall also file the request with the Public Staff.[2] Prior to the effective date, the Public Staff shall schedule the request for Commission consideration at the regularly scheduled staff conference and recommend that the Commission issue an order approving, modifying and approving, or rejecting the proposed sewer system improvement charge. The Public Staff shall formally notify the Commission at least 15 days in advance of the date that the request shall be scheduled for Commission consideration at the regularly scheduled staff conference.

(C) Computation of the SSIC Revenue Requirement.–The SSIC Revenue Requirement shall be computed for each SSIC Period as follows:

[1] The Nags Head sewer operations are not yet eligible for SSIC as the Nags Head service area was not included in this general rate case proceeding.

[2] Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system, for docket number "W-354 Sub 336A", through the Commission's website at www.ncuc.net.

Eligible sewer system improvements	$X,XXX,XXX
Less: Accumulated depreciation	X,XXX,XXX
Less: Accumulated deferred income taxes	X,XXX,XXX
Net plant investment	$X,XXX,XXX
Pre-tax rate of return	X.XX%
Capital costs	$X,XXX,XXX
Plus: Depreciation expense	XXX,XXX
Subtotal, excluding regulatory fee	$X,XXX,XXX
Regulatory fee gross-up factor	XXXX
Total	$X,XXX,XXX

(D) Computation of Sewer System Improvement Charge.

(1) The SSIC shall be expressed as a percentage carried to two decimal places and shall be applied to the total utility bill of each customer under the Company's applicable service rates and charges.

(2) The SSIC shall be computed by dividing the annual SSIC Revenue Requirement by the projected revenues of the Company during the 12-month period following implementation of the charge.

(E) Semi-Annual Adjustments.–The Company may file a request for a SSIC adjustment no more frequently than semiannually.

(1) The request shall include the computation and supporting data for the adjustment.

(2) Cumulative SSIC Revenue Requirements may not exceed 5% of the total annual service revenues approved in this general rate proceeding.

(3) The procedural requirements set forth in subsection (B) of this Appendix shall apply to requests for semi-annual adjustments.

(F) Experience Modification Factor.–The SSIC shall be modified through the use of an experience modification factor (EMF) that reflects the difference between the SSIC Revenue Requirement and the revenues that were actually realized under the SSIC during the SSIC Period. The EMF shall remain in effect for a 12-month period. Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred costs of the Company for eligible sewer system improvements to be refunded to the Company's customers through operation of the EMF shall include an amount of interest at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate.

(G) Sewer System Improvement Charge Reset.–The SSIC shall be reset at zero as of the effective date of new base rates established in the Company's general rate case. Thereafter, only the incremental depreciation expense and capital costs of new eligible sewer system improvements that have not previously been reflected in the Company's rates shall be recovered through the SSIC.

(H) Audit and Reconciliation.–The SSIC shall be subject to the following:

(1) Within 60 days following the end of each SSIC Period, the Company shall file a report, in a format prescribed by the Commission, reconciling its actual eligible sewer system improvement costs, actual SSIC revenues, and EMF computation; and

(2) The Public Staff shall audit the Company's actual eligible sewer system improvement costs, actual SSIC revenues, and EMF computation, and shall file a report on its audit no later than four months after the end of the SSIC Period of the Company.

(I) Ongoing Three-Year Plan.–Within 60 days following the end of each SSIC Period, the Company shall file an updated three-year plan containing the following information:

(1) A three-year plan that includes the following:

a. A detailed description of all proposed eligible sewer system improvements expected to be completed in the SSIC Period and an estimate of the cost of the improvements and dates when the improvements will be placed into service; and

b. A brief description of the proposed eligible sewer system improvements, estimated costs, and completion dates for improvements that the Company plans to complete during the two years following the SSIC Period.

c. Any other information required by the Commission.

(J) Quarterly Filings with the Commission.–Within 45 days after the end of each calendar quarter, the Company shall file the following reports:

(1) A quarterly earnings report consisting of the following:

(a) A balance sheet and income statement for the calendar quarter and calendar year to date for CWSNC;

(b) A statement of the per books net operating income for the calendar quarter and calendar year to date for each rate division (CWSNC uniform water, CWSNC uniform sewer, CLMS sewer operations, and Nags Head sewer operations) based on North Carolina ratemaking and in the same format as the Per Books column on Schedule B of the Company's general rate case application;

(c) A statement of rate base at the end of the calendar quarter for each rate division based on North Carolina ratemaking in the same format as the Per Books column on Schedule C of the Company's general rate case application; and

(d) The number of customers and gallons sold for each month of the calendar quarter for each rate division by rate type (meter size, flat rate, etc.).

(2) A quarterly report of SSIC collections from customers consisting of amounts collected for the quarter by rate division and rate type; and

(3) A construction status report which includes by rate division the following information for each eligible system improvement project: (a) the costs incurred during the quarter; (b) the cumulative amount incurred; (c) the estimated total cost for the project; (d) the estimated completion date; and (e) the actual completion date.

(K) Elimination or Modification of SSIC Mechanism.—After notice to the Company and opportunity to be heard, the Commission may eliminate or modify any previously authorized SSIC mechanism upon a finding that it is not in the public interest.

(L) Burden of Proof.–The burden of proof as to whether a SSIC mechanism is in the public interest, the correctness and reasonableness of any SSIC, and whether the investment in the sewer system improvements was reasonable and prudently incurred shall be on the Company.

CERTIFICATE OF SERVICE

I, _______________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notices to Customers issued by the North Carolina Utilities Commission in Docket No. W-354, Sub 336, and the Notices were mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2014.

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 Notices to Customers were mailed or hand delivered to all affected customers, as required by the Commission Order dated ________________________ in Docket No. W-354, Sub 336.

Witness my hand and notarial seal, this the ____ day of _________, 2014.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ________________________________

DOCKET NO. W-354, SUB 336

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc.	)	ORDER AMENDING PRIOR
of North Carolina, 2335 Sanders Road,	)	ORDER TO CORRECT ERRORS,
Northbrook, Illinois 60062, for Authority to	)	MODIFYING SEWER RATE
Adjust and Increase Rates For Water and	)	DESIGN, IMPLEMENTING GRT
Sewer Utility Service in All Service Areas	)	RATE CHANGES, AND REQUIRING
in North Carolina, Excluding Nags Head	)	REFUND PLAN

BY THE COMMISSION: On June 23, 2014, the Public Staff – North Carolina Utilities Commission (Public Staff), Carolina Water Service, Inc. of North Carolina (CWSNC or Company), and the Corolla Light Community Association, Inc. (CLCA), (collectively, the Parties) filed a Joint Petition to amend the Commission's Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice issued March 10, 2014, in the above-captioned docket, to correct errors, to modify sewer rate structure, and to approve a plan for implementation of tax changes required by House Bill (HB) 998.

In their Petition, the Parties stated that the rates for CWSNC's uniform sewer customers set forth in Exhibit II, attached to the Amended Stipulation and in Appendix A-1 – Sewer Rates and Charges, attached to the Order, are incorrect, and would afford the Company more than the stipulated and Commission-approved CWSNC Uniform – Sewer service revenues of $6,145,062. The Parties recommended that the rates for CWSNC's uniform sewer customers should be corrected pursuant to G.S. 62-80 to accurately reflect the stipulated and Commission-approved revenue requirement.

In addition to correcting the aforementioned errors in rates, the Parties also requested that the Commission authorize, on reconsideration, a prospective change in the rate structure for CWSNC's uniform sewer customers, which is reflected on proposed Appendix C-1 of the Parties' June 23, 2014 filing. According to the Parties, such proposed prospective change would adjust the sewer rate design from approximately a 33/67 ratio between the base facilities charge and the usage charge to approximately a 75/25 ratio.

In support of this request, the Parties stated that since the new rates were placed in effect pursuant to the Commission's March 10, 2014 Order, the Public Staff has received numerous complaints from customers around the State via email, letters, and telephone calls, especially customers on fixed incomes, regarding the change from flat rate sewer service to metered sewer rates and the extremely high bills these customers are now receiving. The Parties commented that while some of the increase in charges is due to the incorrect rates, the ratio of the base charge to the usage charge also appears to have significantly impacted CWSNC's uniform customers' sewer charges.

Further, in the March 10, 2014 Order, the Parties observed that the Commission found it reasonable and appropriate to make a downward adjustment to rates effective July 1, 2014, to recognize the changes in the general franchise/gross receipts tax (GRT) for the Company. Consequently, the Parties requested that the Commission approve rates that reflect the changes due to the repeal of the gross receipts tax, as set forth in proposed Appendices C-1 and C-2 of their filing.

Additionally, with respect to the issue of refunds related to the overcollection resulting from the inadvertent rate errors, the Parties commented that this matter is still under review and discussion, and the Parties agreed to file a report with the Commission regarding this issue within 30 days of a Commission order approving the proposed revised rates.

Lastly, the Parties asserted that it is in the best interest of customers to resolve the tax rate and rate design changes described in the Petition in time for a July 1, 2014 implementation, and thus the Parties respectfully requested that the Commission proceed immediately with the requested changes.

In consideration of the foregoing, the Commission finds and concludes that good cause exists to approve the Joint Petition: (1) to correct the present errors in the existing uniform sewer rate structure to accurately reflect the stipulated and Commission-approved revenue requirement, as established by Order issued March 10, 2014; (2) to modify the existing uniform sewer rate design such that it is based upon a cost-recovery methodology that contemplates recovery of 75% of the annual cost of sewer service (or, synonymously, annual sewer service revenue requirement) through the base facilities charge, with the remaining 25% to be recovered through the usage charge; and (3) to implement legislatively-mandated changes to GRT and the general franchise tax, as effectuated by HB 998.

The Commission further finds and concludes that the aforesaid changes to the Company's rates and charges should be approved, effective July 1, 2014, and that the specific approved rates and charges should be those as set forth in Appendices C-1 and C-2 of the Joint Petition. However, the Commission is further of the opinion that customer bills should continue to be based, for the time being, upon the rates approved by the Commission on March 10, 2014, pending final collective disposition of these matters, including implementation of the Commission's decision as to the manner in which refunds are to be made with respect to the overcollection of revenue due to the rate errors as previously discussed. Lastly, the Commission concludes that, in connection with the final disposition of these matters, the Company should be required to adjust customer bills prospectively so as to provide for the recovery (effective July 1, 2014) of base facilities and usage costs in a manner consistent with the 75%/25% cost-apportionment methodology as approved herein.

Therefore, consistent with the foregoing, the Company is hereby placed on notice that revenues collected in error, beginning March 10, 2014, due to inappropriate rate design, as discussed hereinabove, and the incremental revenue requirement impact associated with the repeal of the GRT and the change in the general franchise tax, beginning July 1, 2014, are hereby deemed to be collected on a provisional basis. Accordingly, such amounts are to be placed in deferred liability accounts pending further order of the Commission.

Finally, the Commission concludes (1) that the Company should be required to file a refund plan for approval by the Commission setting forth the manner in which it would propose to refund deferred amounts collected in error due to inappropriate rate design and amounts related to the incremental revenue requirement impact associated with the repeal of GRT, with interest, and (2) that the Parties should be required to file joint proposed customer notices for approval by the Commission. Said refund plan and proposed customer notices are to be filed not later than Tuesday, July 15, 2014.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the ___1st_____ day of July, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

DOCKET NO. WR-1163, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Carl Mascott, 608 Appleton Drive, Ap. F,	)	
Raleigh, North Carolina 27606,	)	RECOMMENDED ORDER
Complainant	)	AFFIRMING COMPLAINT
	)	IN PART, DISMISSING IN PART,
v.	)	RECALCULATING RATEPAYER
	)	BILLS, AND REQUIRING
Sumare, L.P.,	)	COMPLIANCE WITH COMMISSION
Respondent	)	RULES

HEARD: Wednesday, July 31, 2013, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina.

BEFORE: Corrie V. Foster, Commission Hearing Examiner

APPEARANCES:

FOR COMPLAINANT:

Carl Mascott, 608 Appelton Drive, Apt. F, Raleigh, North Carolina 27606, (pro se).

FOR THE RESPONDENT:

Daniel C. Higgins Esq., Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605.

BY THE HEARING EXAMINER: On May 10, 2013, Carl Mascott (Complainant), filed a complaint against Sumare, L.P. (Respondent), with the North Carolina Utilities Commission (Commission).

On May 13, 2013, the Commission issued an Order Serving Complaint.

On May 17, 2013, Respondent filed a Motion for Extension of Time.

On May 20, 2013, Complainant filed his Motion to Deny Respondent's Motion for Extension of Time.

On May 21, 2013, the Commission issued an Order Granting Respondent's Extension of Time.

On May 31, 2013, Respondent filed its Answer and Motion to Dismiss Complaint.

On June 4, 2013, the Commission issued an Order Serving Answer and Motion to Dismiss Complaint.

On June 12, 2013, Complainant file his Reply indicating that he was not satisfied with Respondent's Answer and requests a hearing.

On June 28, 2013, the Commission issued an Order Scheduling Hearing in this matter. The hearing was scheduled for July 31, 2013, in Raleigh, North Carolina.

On July 31, 2013, the hearing occurred as scheduled. Complainant appeared pro se, to testimony and submit exhibits to the record in support of his claims. Daniel Higgins, Esq., appeared in representation of Respondent, offered the testimony of his witnesses and submitted exhibits in support of Respondent's claims. Brian Willie, Regulatory counsel for NWP Services Corporation, and Carleen Giles, the property manager for Sumter Square Apartment, also appeared at the hearing and testified.

On September 16, 2013, Complainant filed his post hearing brief, motion on proposed order, and a letter regarding his water leak claim. That same day, Respondent submitted its Recommended Order Denying Complaint.

Upon consideration of the testimony, the evidence and exhibits presented at the hearing, and the entire record in this proceeding, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. The Commission issues certificates of authority to utilities to charge its tenants for water and sewer service. The Commission has regulatory authority over these certificate holders.

2. Respondent owns Sumter Square Apartments in Wake County, North Carolina. Respondent purchases its total amount of water monthly from the City of Raleigh. On November 9, 2011, Respondent was issued a certificate of authority from the Commission to charge its tenants pursuant to the Hot Water Capture, Cold Water Allocation Method (HWCCWA), for water and sewer services. As a certificate holder, Respondent is regulated by the Commission.

3. Complainant has lived in the Sumter Square Apartments at 608 Appleton Drive, Apartment F, in Raleigh, North Carolina, since May 2007. He is billed monthly by Respondent for water and sewer service.

4. NWP Services Corporation (NWP) is Respondent's billing contractor. NWP prepares the water and sewer utility bills at the Sumter Square Apartments on a monthly basis.

5. Drucker & Falk, LLC, is the property management company for Sumter Square Apartments. Carleen Giles is the property manager for Sumter Square Apartments.

6. Complainant brought his concerns about his water and sewer bill to Respondent in January 2013.

7. Complainant's water meter was tested for accuracy by a bucket test on February 2013 and found to be accurate.

8. Respondent has provided Complainant with various information regarding its water and sewer billing process.

9. Complainant was not satisfied with Respondent's answers to his requests for information so he filed a complaint with the Commission on May 10, 2013.

10. Respondent is properly before the Commission pursuant to Commission Rule R1-4.

11. The bills from December 2012 to May 2013 sent to Complainant by Respondent at Sumter Square Apartments do not comply with Commission Rule R18-8.

12. Respondent did not use the most up-to-date information from the City of Raleigh to calculate Complainant's monthly water usage.

13. Respondent's administrative fee charge on Complainant's Exhibit A is incorrect.

14. On July 31, 2013, at the evidentiary hearing, Complainant made an oral motion for Respondent to cease and desist billing its ratepayers for water and sewer service until a final order is issued in this proceeding by the Commission. Given that no evidence had been submitted to the record at that time, the Hearing Examiner denied Complainant's motion from the bench.

15. On September 16, 2013, Complainant filed notice with the Commission stating that his issue regarding leaks in several of Respondent's buildings had been resolved and didn't need to be addressed in the Commission's final order.

ARGUMENTS

In this complaint proceeding, Complainant asserts the following three claims: (1) that his water and sewer bills are incorrect and do not contain the information required by Commission rules, (2) the sub-metering operating system and maintenance of meters must be improved, and (3) that there has been several water leaks in several of Respondent's buildings.

Respondent, on the other hand, denies Complainant's first claim and contends that Complainant's utility bills are correct. Respondent, however, does admit that due to past issues with billing, it may have been difficult for someone to independently calculate their water billing. Respondent has worked to reformat its billing to fully comply with Commission Rule R18-8. With regard to Complainant's second claim, Respondent admits that there is a possibility that a hot water meter can malfunction sometime during its service life. However, Respondent argues that such an issue with the meter malfunction would not have a material impact on billing. Additionally, Respondent asserts that the function of the 20% reduction factor used in the HWCCWA of estimating water bills insulates tenants from any billing consequences of such a malfunction. Finally, Respondent admits that it investigated six of its buildings and discovered water leaks at two of the buildings. However, the leaks in question were quickly addressed and repaired by American Leak Detection.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The Hearing Examiner notes that Complainant, prior to providing testimony and the submission of exhibits, made an oral motion requesting that Respondent be ordered to cease and desist billing its ratepayers for water and sewer service until a final order is issued in this proceeding by the Commission. Given that no evidence had been submitted to the record at that time, the Hearing Examiner denied Complainant's motion from the bench.

North Carolina General Statute (G.S.) 62-75, in relevant part, indicates that the burden of proof in complaint proceedings is upon the Complainant to show that the action of the utility with regard to its rates, services, classification, rules, regulations or practice is unjust and unreasonable. The Complainant may meet this burden of proof with the submission of evidence, including testimony and exhibits that would be admissible in a court of law, in support of the complaint at an evidentiary hearing.

After reviewing the law, Commission Rules, testimony of the witnesses and the exhibits submitted to the record, the Hearing Examiner finds and concludes that Complainant has meet his burden of proof in the Complaint in part. The Commission further finds good cause to order Respondent to recalculate Complainant's bills and to begin to immediately comply with the Commission's billing procedures under Rule R18-8.

The Hearing Examiner takes judicial notice of the Order Granting Certificate of Authority and Approving Rates in Docket No. WR-1163, Sub 0 issued by the Commission on November 9, 2011. In the Order, the Commission grants Respondent operating authority to charge its customers in Sumter Square Apartments in Wake County, North Carolina, pursuant to the HWCCWA for water and sewer service.

As a holder of a certificate from the Commission, Respondent must comply with the pertinent provisions of Chapter 62 and the Commission's Rules. Specifically, Commission Rule R18-8 requires that utilities that possess a certificate of authority to charge water and/or sewer service must inform its customers that their bills are estimated pursuant to the HWCCWA. Additionally, the bills provided to tenants by the utilities are required to contain the following information:

1. Total amount of water purchased by the provider.
2. Total amount of water purchased less the metered and/or allocated common area usage (utilizing one of the methods allowed by the Commission).
3. Total amount of hot water measured for all tenants.
4. Amount of hot water measured for the individual tenant.
5. Amount of water the individual tenant is being billed.
6. Amount owed for the current billing period.
7. Beginning and ending dates for the billing period.
8. Past due date.
9. A local or toll-free telephone number and address that the tenant can use to obtain more information about the bill.

In this particular case, the facts and circumstances show that Complainant has met his burden in his **first claim** and had reason to be skeptical of his utility bills. The first bill submitted into evidence by Complainant, marked as Mascott Exhibit A, covered the billing period of 12/1/2012 to 12/31/2012. The bill extended thirty (30) days of service and totaled $50.16. The bill's content was quite deficient. There was no way for Complainant to calculate his bill because it did not contain the information required by Commission's Rule. Specifically, the bill did not contain the following: (1) total amount of water purchased, (2) water purchased less the metered and/or allocated common area usage, and (3) total amount of hot water measured for all tenants. The bill also indicates that the usage is determined in 5 gallon units.[1]

The bill also shows that Respondent charged the incorrect administrative fee for water and sewer service. The administrative fee on the bill totals $4.62 which is comprised of $3.75 meter, billing, and collection costs plus a pass through of Raleigh's $0.87 base charge. However, the actual administrative fee that was approved by the Commission at that time was $4.59 ($3.75 meter, billing, and collection costs plus a pass through of Raleigh's $0.84 base charge for water and sewer services).[2] The bill also contained an entry for a $10.00 charge for Electric/Gas/Water Service Type. It is not exactly clear why this charge was included on the bill so close to the water and sewer charge information. This entry could have easily been confused as being a Commission approved charge, which it was not. This charge would be better served on another section on the bill separate from the Commission's approved charges. Overall, Respondent's bill should have been better organized so that it clearly identifies the approved charges. By taking such care, it would make it easier for tenants to calculate their bills. Given that Respondent failed to include the required information on its bills, Complainant could not even begin to calculate his bills.

Finally, the facts show that Respondent's bills were not calculated using up-to-date data of its overall water purchase from the City of Raleigh. According to the record, Respondent used data that did not match with the actual dates, in which the tenant used the service. The Hearing Examiner understands that the HWCCAW is largely a method of estimation of a consumer's water and sewer use, however, Respondent must arrive at the estimation after using the appropriate information. Specifically, Respondent must use the precise information available to it at that time. This means to use the actual amount it costs for it to purchase its bulk water from the City of Raleigh which correlates to the time period that it charges its tenants and the exact amount approved by the Commission. For Respondent to simply argue that the billing process is an estimation process is insufficient.

In Complainant's **second claim**, he asserts that Respondent's submetering operation system and the maintenance of the water meters must be improved. Despite this argument, the record shows that Complainant has presented no evidence that the meters in Respondent's buildings have failed or are in jeopardy of failing. Much of Complainant's concerns are theoretical

[1] The Commission learned that the number used by Respondent was fictitious and had no actual impact on the determination of the tenant's overall usage.

[2] N.C.U.C. Docket No. WR-1163, Sub 1, (April 25, 2012) (the Commission approved a monthly fee of $4.59 comprising of a $3.75 meter reading, billing, and collecting costs plus a pass through of Raleigh's $0.84 base charge for water and sewer service. The Commission further authorized that Sumter customers could be charged $3.94 per 1,000 gallon for water and $3.89 per 1,000 gallon for sewer.).

as to the potential impact that failed meters could have on the calculation of a tenant's water and sewer bill. In fact, Complainant has resided in Sumter Square Apartments since May of 2007 and has never previously reported a problem with his water meter. Moreover in 2013, Complainant did request that Respondent test his water meter. Pursuant to his request, Respondent tested Complainant's water meter using the bucket method and it was found to be accurate.[1] Complainant was present when the test was performed on his meter and did not make any arguments or submit any evidence at the hearing to suggest that the test results should not be relied upon by the Commission. Based upon the foregoing information, the Hearing Examiner finds and concludes that Complainant has failed to meet his burden of proof with regard to the second claim in his complaint.

The Hearing Examiner now addresses the Complainant's **third claim** in his complaint. In this claim, Complainant alleges that Respondent had several water leaks in its buildings. On September 16, 2013, however, Complainant filed notice with the Commission stating that this particular claim had been resolved and that it did not need to be addressed in the Commission's final order. Because Complainant made such a filing with the Commission indicating that he no longer desires to pursue that claim, the Hearing Examiner takes no further action regarding that claim and dismisses it.

Although Complainant would disagree, the Hearing Examiner finds that Respondent has been responsive to Complainant's requests for information and has worked in good faith to resolve his claims. This was evident in Respondent's efforts to comply with Complainant's extensive requests for information. The Hearing Examiner understands Complainant's concern with regard to his water and sewer bills. The Hearing Examiner is further aware that Respondent did deny Complainant some information that it considered confidential. The Hearing Examiner understands the predicament that Respondent found itself in while attempting to provide Complainant with the information he sought. Respondent was placed in the position that it could have potentially violated another tenant's privacy by providing information, which the Complainant was not clearly entitled to receive or to incur unreasonable expense to provide to him in a fashion that particularly suited the Complainant. There is no doubt that Complainant is entitled to receive information about his individual bill. However, the Complainant has presented no Commission rule, which entitles him to such expanded information that he requested and in the particular form he requested it.

The Hearing Examiner is encouraged to learn that Respondent has taken proactive steps in improving its billing procedures. In fact, the record indicates that Respondent was working to align its billing dates with that of the City of Raleigh. However, the record does show that Respondent's bills were deficient of the required information. Respondent did not use up-to-date information on its bulk water purchases from the City of Raleigh, and charged Complainant the incorrect administrative fee on his bills. Based on the foregoing, the Hearing Examiner finds and concludes that Complainant has met his burden in part with regard to the first claim in his complaint and orders Respondent to recalculate the bills in question. The Hearing Examiner further finds and concludes that Complainant's remaining allegations, which are identified as his second and third claims, are dismissed.

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[1] According to Complainant, his meter was tested twice, the first test was invalidated, so it was tested a second time and the results found it to be accurate.

IT IS, THEREFORE, ORDERED as follows:

1. That Respondent shall recalculate the Complainant's bills beginning with December 2012, until August 2013, using the correct regulated charges approved by the Commission;

2. That within 30 days of issuance of this Order, the Respondent shall submit its calculations (showing the values required on the bill [#1 through 7, above] for each bill recalculated) to the Commission for review and approval;

3. That the Respondent, if not already done so, shall immediately comply with Commission Rule R18-8, by including the required information on all its bills in the Sumter Square Apartments in Wake County, North Carolina;

4. That the Complainant's allegations identified as his second and third claims are dismissed; and

5. That this Order shall be served on Complainant by United States certified mail, return receipt requested and on Respondent by electronic mail, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of December, 2014.

NORTH CAROLINA UTILITIES COMMISSION
Paige J. Morris, Deputy Clerk

ORDERS AND DECISIONS -- PRINTED

INDEX OF ORDERS PRINTED

ORDERS AND DECISIONS -- PRINTED

ORDERS AND DECISIONS -- PRINTED

ORDERS AND DECISIONS LISTED

GENERAL ORDERS

GENERAL ORDERS -- General

M-100, SUB 113; Order Granting Petition to Modify CIAC Reporting Requirements for Electric Utilities (06/19/2014)

M-100, SUB 138; Order Addressing the Impacts of HB 998 on North Carolina Public Utilities (05/13/2014)

M-100, SUB 138; E-2, SUB 1046; Order Approving Proposal and Requiring Filing of Revised Tariffs (06/17/2014); Order Approving Tariffs (07/21/2014); Order Approving Proposal and Tariffs (12/17/2014)

M-100, SUB 138; E-7, SUB 1058; Order Approving Proposal and Requiring Filing of Revised Tariffs (06/17/2014); Order Approving Tariff (07/21/2014); Order Approving Proposal and Tariffs (12/17/2014)

M-100, SUB 138; E-22, SUB 506; Order Approving Tariffs (07/21/2014); Order Approving Proposal and Tariffs (12/18/2014)

M-100, SUB 138; E-34, SUB 42; Order Approving Schedule of Rates (07/21/2014)

M-100, SUB 138; G-5, SUB 549; Order Approving Proposal and Requiring Filing of Revised Tariffs (06/20/2014); Order Approving Summary of Rates and Charges (06/27/2014); Order Approving Proposal and Summary of Rates and Charges (12/19/2014)

M-100, SUB 138; G-39, SUB 33; Order Approving Proposal and Requiring Filing of Revised Tariffs (06/12/2014); Order Approving Tariffs (06/30/2014); (12/04/2014)

M-100, SUB 138; W-354, SUB 342; Order Approving Tariffs (06/27/2014)

M-100, SUB 138; W-354, SUB 342; W-778, SUB 90; W-1012, SUB 14; W-1013, SUB 10; W1044, SUB 20; W-1058, SUB 6; Order Approving Proposals and Requiring Filing of Revised Tariffs (06/12/2014)

M-100, SUB 138; W-406, SUB 5; Order Approving Rates and Requiring the Filing of Revised Tariffs (12/05/2014); Order Approving Customer Notice and Revised Tariffs (12/17/2014)

M-100, SUB 138; W-778, SUB 90; Order Approving Tariffs (06/27/2014)

M-100, SUB 138; W-1012, SUB 14; Order Approving Tariffs (06/27/2014)

M-100, SUB 138; W-1013, SUB 10; Order Approving Tariffs (06/27/2014)

M-100, SUB 138; W-1044, SUB 20; Order Approving Tariffs (06/27/2014)

M-100, SUB 138; W-1058, SUB 6; Order Approving Tariffs (06/27/2014)

M-100, SUB 138; W-1282, SUB 11; Order Approving Proposal and Requiring Filing of Revised Tariffs (06/12/2014); Order Approving Tariffs (06/27/2014)

M-100, SUB 139; P-100, SUB 99; Order Adopting Revisions to Commission Rules R1-28 and R9-8(d) (05/13/2014)

ORDERS AND DECISIONS LISTED

GENERAL ORDERS – Electric

E-100, SUB 130; EMP-44, SUB 0; EMP-45, SUB 0; EMP-64, SUB 0; EMP-67, SUB 0; SP-275, SUB 1; SP-578, SUB 0; SP-665, SUB 0; SP-716, SUB 0; SP-719, SUB 0; SP-815, SUB 0; SP-991, SUB 0; SP-1022, SUB 0; SP-1039, SUB 0; SP-1039, SUB 2; SP-1049, SUB 0; SP-1060, SUB 1; SP-1081, SUB 0; SP-1122, SUB 0; SP-1246, SUB 0; SP-1278, SUB 1; SP-1321, SUB 1; SP-1383, SUB 1; SP-1399, SUB 1; SP-1454, SUB 3; SP-1490, SUB 1; SP-1550, SUB 0; SP-1652, SUB 0; SP-1665, SUB 0; SP-1676, SUB 0; SP-1690, SUB 0; SP-1706, SUB 1; SP-1708, SUB 0; SP-1723, SUB 1; SP-1724, SUB 1; SP-1725, SUB 1; SP-1740, SUB 1; SP-1770, SUB 0; SP-1793, SUB 1; SP-1810, SUB 0; SP-2001, SUB 3; SP-2001, SUB 4; SP-2001, SUB 5; SP-2041, SUB 0; SP-2119, SUB 0; SP-2185, SUB 0; SP-2211, SUB 0; SP-2220, SUB 0; SP-2283, SUB 0; SP-2320, SUB 0; SP-2322, SUB 0; SP-2350, SUB 0; SP-2351, SUB 0; SP-2354, SUB 0; SP-2378, SUB 0; SP-2430, SUB 0; SP-2606, SUB 1; SP-2635, SUB 0; SP-2816, SUB 0; SP-2875, SUB 0; SP-2899, SUB 0; SP-2910, SUB 3; SP-2951, SUB 0; SP-3050, SUB 0; Order Revoking Registration of Renewable Energy Facilities and New Renewable Energy Facilities (11/19/2014)

E-100, SUB 130; Errata Order (11/26/2014)

E-100, SUB 130; EMP-44, SUB 0; EMP-45, SUB 0; Errata Order (11/20/2014)

E-100, SUB 135; Order Approving 2011 REPS Compliance and Requiring Additional Measurement and Verification of Energy Efficiency Measures (02/18/2014)

E-100, SUB 139; Order Approving 2012 REPS Compliance and Requiring Additional Information (10/06/2014)

GENERAL ORDERS -- Electric Reseller

ER-100, SUB 0; Order Amending Final Rules (03/26/2013); (03/31/2014); Errata Order (08/27/2014)

GENERAL ORDERS -- Telecommunications

P-100, SUB 99; P-100, SUB 99A; P-1154, SUB 5; Order Affirming Previous Commission Order Canceling Certificate *(Momentum Telecom, Inc.)* (03/04/2014)

P-100, SUB 99; P-100, SUB 99A; P-1223, SUB 2; Order Affirming Previous Commission Order Canceling Certificate *((Teledias Communications, Inc.)* (03/04/2014)

P-100, SUB 99; M-100, SUB 139; Order Adopting Revisions to Commission Rules R1-28 and R9-8(d) (05/13/2014)

P-100, SUB 99; P-100, SUB 99A; P-1475, SUB 2; Order Affirming Previous Commission Order Canceling Certificate *(NET TALK.COM, INC.)* (03/04/2014)

P-100, SUB 99; P-100, SUB 99A; P-1487, SUB 2; Order Affirming Previous Commission Order Canceling Certificate *(American Telecom, Inc.)* (03/04/2014)

P-100, SUB 99; P-100, SUB 99A; P-1468, SUB 2; Order Affirming Previous Commission Order Canceling Certificate *(Fast Phones, Inc.)* (03/05/2014)

<u>GENERAL ORDERS – Telecommunications</u> *(Continued)*

P-100, SUB 133C; P-1278, SUB 3; Order Granting Petition to Discontinue Service and Cancelling EveryCall Communications Inc.'s Designation as Eligible Telephone Carrier (05/16/2014)

P-100, SUB 170; P-1558, SUB 1; Order Affirming Previous Commission Order Cancelling Certificate (10/22/2014); *(Equinox Global Telecommunications, Inc.)* (10/22/2014)

P-100, SUB 170; P-1567, SUB 2; Order Affirming Previous Commission Order Cancelling Certificate (10/22/2014); *(Wide Voice, LLC)* (10/22/2014)

<u>GENERAL ORDERS -- Transportation</u>

T-100, SUB 49; Order Granting Annual Rate Increase (12/04/2014)

T-100, SUB 90; Errata Order (10/10/2014); Second Errata Order (10/27/2014); Third Errata Order (11/14/2014)

T-100, SUB 92; T-4467, SUB 3; Order Canceling Certificate of Exemption *(CEH Moving, Inc.)* (02/07/2014)

T-100, SUB 92; T-4472, SUB 2; Order Canceling Certificate of Exemption *(Dawes Moving Service)* (02/07/2014)

T-100, SUB 92; T-2490, SUB 10; Order Canceling Certificate of Exemption *(DeHaven's Transfer & Storage of Raleigh, Inc.)* (02/07/2014)

T-100, SUB 92; T-3255, SUB 9; Order Canceling Certificate of Exemption *(DeHaven's Transfer & Storage of Wilson, Inc.)* (02/07/2014)

T-100, SUB 92; T-4417, SUB 2; Order Canceling Certificate of Exemption *(Nevius Logistics, LLC)* (02/07/2014)

T-100, SUB 92; T-4313, SUB 4; Order Canceling Certificate of Exemption *(Parks Transfer)* (02/07/2014)

T-100, SUB 92; T-4447, SUB 3; Order Canceling Certificate of Exemption *(Regency Moving & Storage, LLC)* (02/07/2014)

T-100, SUB 92; T-4455, SUB 2; Order Canceling Certificate of Exemption *((Sossamon's Conveyance, LLC) (*02/07/2014)

T-100, SUB 92; T-4501, SUB 2; Order Canceling Certificate of Exemption *(Unique Movers)* (02/07/2014)

T-100, SUB 92; Order Lifting Suspensions (02/06/2014)

T-100, SUB 95; T-1439, SUB 7; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Umstead Brothers, Inc.)* (10/13/2014)

T-100, SUB 96; T-855, SUB 9; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Jackson Moving & Storage Company)* (10/13/2014)

T-100, SUB 96; T-1852, SUB 11; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Sandhills Moving & Storage Co.)* (10/13/2014)

T-100, SUB 96; T-4124, SUB 4; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(American Moving Systems & Storage, Inc.)* (10/13/2014)

T-100, SUB 96; T-4170, SUB 4; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(McCollister's Transportation Systems, Inc.)* (10/13/2014)

T-100, SUB 96; T-4351, SUB 4; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Murphy Movers, Inc.)* (10/13/2014)

GENERAL ORDERS – Transportation *(Continued)*

T-100, SUB 96; T-4430, SUB 4; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Principle Moving, Inc.)* (10/13/2014)

T-100, SUB 96; T-4468, SUB 1; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Moving Forward Trucking, LLC)* (10/13/2014)

T-100, SUB 96; T-4518, SUB 2; Order Affirming Previous Commission Order Cancelling Certificate of Exemption *(Bones Taylor Moving, LLC)* (10/13/2014)

GENERAL ORDERS – Water and Sewer

W-100, SUB 55; Recommended Order Finding Violation and Appropriate Penalty *(Bay Tree)* (10/31/2014)

W-100, SUB 55; Recommended Order Finding Violation and Appropriate Penalty *(Piedmont Water & Sewer, LLC)* (10/31/2014); Order Excusing Penalty (11/06/2014)

W-100, SUB 55; Recommended Order Finding Violation and Appropriate Penalty *(Webb Creek Water and Sewage, Inc.)* (10/31/2014); Order Excusing Penalty (11/07/2014)

BUS BROKER

BUS BROKER -- Cancellation of Certificate

Albertson; Charles W. – B-332, SUB 1; Order Cancelling Broker's License (11/18/2014)

Davis Tours, Inc. – B-342, SUB 2; Order Canceling Broker's License (01/09/2014)

Per-Flo Tours, Inc. -- B-321, SUB 2; Order Cancelling Broker's License (10/27/2014)

Megabus.com – B-701, SUB 3; Order Cancelling Certificate (11/19/2014)

ELECTRIC

ELECTRIC -- Adjustments of Rates/Charges

Dominion North Carolina Power – E-22, SUB 515; Order Approving Fuel Charge Adjustment (12/18/2014)

Duke Energy Progress, Inc. **–** E-2, SUB 1045; Order Approving Fuel Charge Adjustment (11/19/2014)

New River Light and Power Company – E-34, SUB 41; Order Approving Purchased Power Adjustment Factor (01/23/2014); Order Approving Correction of Filed Rates (02/20/2014)

Western Carolina University – E-35, SUB 43; Order Approving Purchased Power Cost Rider (01/22/2014)

ORDERS AND DECISIONS LISTED

ELECTRIC -- Complaint

Duke Energy Carolinas, LLC -- E-7,

SUB 1036; Recommended Order Dismissing Complaint *(Eben Snow)* (05/02/2014)

SUB 1037; Recommended Order Dismissing Complaint and Granting Modified Motion to Compel (01/09/2014); Final Order Overruling Exceptions and Affirming and Modifying Recommended Order *(Sonya Allen)* (08/27/2014)

SUB 1040; Recommended Order for Dismissing Complaint *(Albert McGibboney)* (06/23/2014); Errata Order (06/25/2014)

SUB 1044; Recommended Order Denying Continuance and Dismissing Complaint (07/18/2014); Final Order Affirming Recommended Order *(Jerome Pelzer)* (09/03/2014)

SUB 1048; Order Dismissing Complaint and Closing Docket *(Andrew L. Bell)* (04/04/2014)

SUB 1049; Order Dismissing Complaint and Closing Docket *(E. von Muggenthaler, Ph.D.)* (04/16/2014)

SUB 1053; Order Dismissing Complaint and Closing Docket *(Robert D. Jernigan)* (05/19/2014)

SUB 1054; Recommended Order Granting in Part and Denying in Part the Relief Requested by Complainant (07/11/2014); Final Order Affirming Duke Energy Carolinas, LLC's Exceptions, Overruling Complainant's Exceptions, and Accepting Duke's Payment Plan Offer *(Jose J. Moran)* (11/04/2014)

SUB 1057; Order Dismissing Complaint and Closing Docket *(William J. Phelan)* (06/19/2014)

SUB 1061; Order Dismissing Complaint and Closing Docket *(P. M. Segal & Company)* (11/24/2014)

SUB 1064; Order Dismissing Complaint and Closing Docket *(Anthony Alvarado)* (11/06/2014)

SUB 1065; Order Dismissing Complaint and Closing Docket *(Reginald Flowe)* (11/17/2014)

SUB 1067; Order Dismissing Complaint and Closing Docket *(Lloyd R. Flowers)* (11/10/2014)

Duke Energy Progress, Inc. -- E 2,

SUB 1034; Recommended Order Dismissing Complaint *(Iris D. Williams)* (02/05/2014)

SUB 1038; Order Dismissing Complaint and Closing Docket *(David Champagne)* (05/19/2014)

SUB 1040; Order Accepting Voluntary Dismissal and Closing Docket *(Montgomery Solar, LLC)* (07/10/2014)

SUB 1050; E-7, SUB 1060; E-22, SUB 511; Order Accepting Dismissal of Complaint and Petition for Arbitration *(Coastal Carolina Clean Power LLC)* (11/13/2014)

ELECTRIC -- Contract/Agreements

Dominion North Carolina Power – E-22, SUB 512; Order Accepting Affiliate Agreements and Authorizing Payment Thereunder (12/22/2014)

Duke Energy Carolinas, LLC -- E-7, SUB 1041; Order Closing Docket (10/10/2014)

Duke Energy Progress, Inc. – E-2, SUB 1052; E-7, SUB 1062; Order Accepting Affiliate Agreements, Allowing Payment Thereunder and Granting Limited Waiver of Code of Conduct (10/29/2014)

ORDERS AND DECISIONS LISTED

ELECTRIC – Filings Due Per Order

Duke Energy Carolinas, LLC – E-7, SUB 986A; E-2, SUB 998A; Order Allowing Continued Participation in Money Pool Agreement (12-22-2014)

Duke Energy Progress, Inc. -- E-2, SUB 998A; E-7, SUB 986A; Order Approving Request for Limited Waiver and Pre-Approval of Accounting Authority Pursuant to Rule R8-27 (09/03/2014)

ELECTRIC -- Merger

Duke Energy Progress, Inc. – E-2, SUB 998; E-7, SUB 986; Order Approving Termination of Merger Capacity Mitigation Riders (10/31/2014)

ELECTRIC -- Miscellaneous

Dominion North Carolina Power – E-22,

SUB 508; Order Approving Program (10/27/2014)

SUB 509; Order Approving Program (10/27/2014)

SUB 516; Order Approving Waiver Request (09/30/2014)

Duke Energy Carolinas, LLC -- E-7,

SUB 986D; Order Approving Audit Procedural Schedule (10/10/2014)

SUB 1026; Order Approving Revised Lighting Tariffs (10/10/2014)

SUB 1052; Errata Order (08/28/2014)

Duke Energy Progress, Inc. – E-2,

SUB 1023; Order Approving Plan for Distribution of Ratepayer Assistance Funds (02/27/2014)

SUB 1041; Order Approving Revised Lighting Schedules and Agreement and Stipulation of Settlement (09/15/2014)

SUB 1053; Order Approving Duke Energy Progress's Line Extension Plan E (11/12/2014)

ELECTRIC – Rate Increase

Duke Energy Carolinas, LLC -- E-7,

SUB 1026; Order Approving Rider (06/16/2014); Order Approving Coal Inventory Rider True-Up Adjustment (08/27/2014)

SUB 1051; Order Approving Fuel Charge Adjustment (08/14/2014)

SUB 487; SUB 828; SUB 989; Order Approving EDPR Rider (06/16/2014)

ELECTRIC – Rate Schedules/Riders/Service Rules and Regulations

Dominion North Carolina Power – E-22,

SUB 463; Order Granting Motion to Offer North Carolina-Only Low Income Program (09/09/2014)

SUB 467; SUB 469; Order Granting Motion to Close Programs (08/13/2014)

SUB 513; Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (12/19/2014)

ELECTRIC – Rate Schedules/Riders/Service Rules and Regulations *(Continued)*

Duke Energy Carolinas, LLC -- E-7,
SUB 458; Order Approving Modifications of Sample Test Plan (02/05/2014)
SUB 961; Order Approving Program (08/13/2014)
SUB 986A; Order Accepting Financing Plan (02/04/2014)
SUB 1032; Order Approving Termination of Program (11/26/2014)
SUB 1050; Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (10/29/2014)

Duke Energy Progress, Inc. – E-2,
SUB 238; Order Approving Modification of Sample Test Plan (02/05/2014)
SUB 979; Order Approving Rider Revision (11/12/2014)
SUB 989; Order Approving Program (12/18/2014)
SUB 1044; Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (11/25/2014)
SUB 1059; Order Approving Program (12/18/2014)
SUB 1060; Order Approving Program (12/18/2014)

ELECTRIC – Securities

Duke Energy Progress, Inc. -- E-2, SUB 1049; E-2, SUB 939; Order Granting Authority to Issue and Sell Securities (07/30/2014)

ELECTRIC – Transmission Line Certificate

Duke Energy Carolinas, LLC – E-7,
SUB 1045; Order Waiving Notice and Hearing Requirement and Issuing Certificate (02/20/2014)
SUB 1046; Order Issuing Certificate and Waiving Notice and Hearing Requirement (02/26/2014)

Duke Energy Progress, Inc. – E-2, SUB 1039; Order Waiving Notice and Hearing Requirement and Issuing Certificate (08/27/2014)

ORDERS AND DECISIONS LISTED

ELECTRIC MERCHANT PLANTS

ELECTRIC MERCHANT PLANTS – Certificate

Morgans Corner Solar Energy LLC -- EMP-86, SUB 0; Order Granting Certificate with Conditions and Accepting Registration of New Renewable Energy Facility (12/03/2014)

NTE Carolinas, LLC -- EMP-76, SUB 0; Order Granting Certificate (10/28/2014)

Pantego Wind Energy LLC -- EMP-61, SUB 0; Order Renewing Certificate (06/30/2014)

ELECTRIC MERCHANT PLANTS – Filings Due Per Order

Anacacho Wind Farm, LLC -- EMP-80, SUB 0; Order Accepting Registration of New Renewable Energy Facility (07/21/2014)

Forest Creek Wind Farm, LLC -- EMP-81, SUB 0; Order Accepting Registration of New Renewable Energy Facility (07/21/2014)

Goldthwaite Wind Energy, LLC -- EMP-75, SUB 0; Order Accepting Registration of New Renewable Energy Facility (10/14/2014)

Magic Valley Wind Farm I, LLC -- EMP-79, SUB 0; Order Accepting Registration of New Renewable Energy Facility (07/21/2014)

Papalote Creek Wind Farm II, LLC -- EMP-77, SUB 0; Order Accepting Registration of New Renewable Energy Facility (07/21/2014)

Pattern Panhandle Wind, LLC -- EMP-82, SUB 0; Order Accepting Registration of New Renewable Energy Facility (12/05/2014)

Pattern Panhandle Wind 2, LLC -- EMP-83, SUB 0; Order Accepting Registration of New Renewable Energy Facility (12/05/2014); Errata Order (12/08/2014)

RockTenn CP, LLC -- EMP-71, SUB 1; Order Accepting Registration of Renewable Energy Facility (05/12/2014)

Sand Bluff Wind Farm, LLC -- EMP-78, SUB 0; Order Accepting Registration of New Renewable Energy Facility (07/21/2014)

ELECTRIC MERCHANT PLANTS – Sale/Transfer

East Carolina Energy Investments, LLC -- EMP-18, SUB 1; EMP-19, SUB 1; EMP-84, SUB 0; EMP-85, SUB 0; Order on Proposed Transfers of Facilities and Certificates (08/06/2014)

ELECTRIC RESELLER

ELECTRIC RESELLER – Certificate

Breckenridge Group Charlotte North Carolina, LLC -- ER-39, SUB 0; Order Granting Certificate of Authority (12/31/2014)

Carrboro II, LLC -- ER-16, SUB 0; Order Granting Certificate of Authority (03/05/2014)

CEV Greensboro LP -- ER-26, SUB 0; Order Granting Certificate of Authority (05/13/2014)

CEV Greensboro II LP -- ER-38, SUB 0; Order Granting Certificate of Authority (12/09/2014)

Collins Crossing Terraces LLC -- ER-35, SUB 0; Order Granting Certificate of Authority (07/28/2014)

North Carolina Carrboro L. P. -- ER-17, SUB 0; Order Granting Certificate of Authority (03/05/2014)

Progress Wilmington, LLC -- ER-40, SUB 0; Order Grant. Certif. of Authority (12/31/2014)

ORDERS AND DECISIONS LISTED

FERRYBOATS

FERRYBOATS -- Adjustments of Rates/Charges

Bald Head Island Transportation, Inc. -- A-41, SUB 13; Order Reducing Fuel Surcharge Effective October 1, 2014 (09/16/2014)

FERRYBOATS -- Cancellation of Certificate

ORDER CANCELLING CERTIFICATE
Orders Issued

Company	Docket No.	Date
Barrier Island Transportation Service, Inc.	A-37, SUB 5	(06/19/2014)
Calico Jack' Ferry	A-46, SUB 5	(07/18/2014)
Cape Pointe Ferry	A-67, SUB 1	(06/19/2014)
Crystal Coast Ferry Service, LLC	A-72, SUB 1	(07/10/2014)
Local Yokel Ferry & Tours; The	A-54, SUB 3	(07/17/2014)
Sea Skimmer Boats	A-68, SUB 1	(09/11/2014)
Soundside Shuttle	A-71, SUB 3	(06/23/2014)

FERRYBOATS – Sale/Transfer

Outer Banks Ferry Service -- A-40, SUB 2; A-74, SUB 1; Order Approving Sale and Transfer and Name Change (08/07/2014)

Island Ferry Adventures -- A-40, SUB 2; Order Granting Request to Cancel Portion of Authority (09/04/2014); Errata Order (09/04/2014)

FERRYBOATS – Suspension

Island Ferry Adventures -- A-74, SUB 2; Order Granting Authorized Suspension (07/10/2014)

LO'R Decks at Calico Jacks Ferry -- A-69, SUB 1; Order Granting Authorized Suspension (07/14/2014)

Waterfront Ferry Service, Inc. -- A-55, SUB 4; Order Granting Authorized Suspension (07/31/2014)

HOUSING AUTHORITY

HOUSING AUTHORITY -- Certificate

Housing Authority/City of Salisbury -- H-71, SUB 0; Order Granting Certificate and Canceling Hearing (04/25/2014)

ORDERS AND DECISIONS LISTED

NATURAL GAS

NATURAL GAS – Adjustments of Rates/Charges

Cardinal Pipeline Company, LLC -- G-39, SUB 32; Order Approving Fuel Tracker and Electric Power Cost Adjustment (03/27/2014)

Frontier Natural Gas Company, LLC -- G-40,
SUB 119; Order on Annual Review of Gas Cost (04/14/2014)
SUB 122; Order Allowing Rate Changes Effective March 1, 2014 (02/26/2014)
SUB 126; Order Allowing Rate Changes Effective November 1, 2014 (10/29/2014)
SUB 127; Order Allowing Rate Changes Effective January 1, 2015 (12/22/2014)

Municipal Gas Authority of Georgia/City of Toccoa, Georgia -- G-41, SUB 41; Order Allowing Rate Changes Effective June 1, 2014 (06/02/2014)

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 641; Order Approving Rate Adjustments Effective February 1, 2014 (02/05/2014)
SUB 643; Order Allowing Rate Changes Effective February 1, 2014 (01/28/2014)
SUB 646; Order Approving Rate Adjustments Effective March 1, 2014 (03/06/2014)
SUB 647; Order Approving Rate Adjustments Effective April 1, 2014 (04/01/2014)
SUB 650; Order Allowing Rate Changes Effective May 1, 2014 (04/28/2014)
SUB 653; Order on Annual Review of Gas Costs (11/21/2014)
SUB 658; M-100, SUB 138; G-9, SUB 631; Order Approving Rate Adjustments Effective November 1, 2014 (10/29/2014)
SUB 660; Order Allowing Rate Changes Effective January 1, 2015 (12/22/2014)

Public Service Company of North Carolina, Inc. -- G-5,
SUB 547; Order Approving Rate Adjustments Effective April 1, 2014 (04/01/2014)
SUB 548; Order on Annual Review of Gas Costs (09/29/2014)
SUB 550; Order Approving Rate Adjustments Effective October 1, 2014 (09/30/2014)
SUB 552; Order Approving Rate Adjustments Effective November 1, 2014 (10/28/2014)

NATURAL GAS – Contract/Agreements

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 634; Order Allowing Contract to Become Effective (02/20/2014)
SUB 638; Order Allowing Agreement to Become Effective (02/20/2014)
SUB 640; Order Allowing Agreement to Become Effective (03/27/2014)
SUB 652; Order Approving Agreement (08/13/2014)
SUB 654; Order Approving Amended Agreement (10/28/2014)
SUB 655; Order Accepting Affiliated Agreements for Filing and Permitting Operation Thereunder Pursuant to G.S. 62-153 and Authorizing Piedmont to Enter Into Related Redelivery Agreements (10/28/2014)
SUB 656; Order Approving Agreement (11/26/2014)

Public Service Company of North Carolina, Inc. -- G-5, SUB 400A; G-5, SUB 546; Order Amending Code of Conduct and Accepting Asset Transfer Agreement (04/15/2014)

ORDERS AND DECISIONS LISTED

NATURAL GAS – Miscellaneous

***Frontier Natural Gas Company, LLC* --** G-40, SUB 120; Order Accepting Notice of Withdrawal and Closing Docket (07/23/2014)

***Municipal Gas Authority of Georgia/City of Toccoa, Georgia* --** G-41, SUB 42; Order on Annual Review of Gas Costs (12/19/2014)

***Public Service Company of North Carolina, Inc.* --** G-5, SUB 551; Order Allowing Adjustment of Franchised Territories (10/07/2014)

NATURAL GAS – Rate Increase

Piedmont Natural Gas Company, Inc. -- G-9, SUB 631; Order Granting Vehicular Natural Gas Tariff Revisions (04/28/2014)

NATURAL GAS – Rate Schedules/Riders/Service Rules & Regulations

Public Service Company of North Carolina, Inc. -- G-5,

SUB 525; Order Allowing Continuance of and Modifications to Rate Schedule 135 -- Natural Gas Vehicle Fuel (09/24/2014)

SUB 545; Order Allowing Modified Billing of Rider A Customers Pending Hearing on Petition (03/06/2014); Order Clarifying Modified Billing of Rider A Customers Pending Hearing on Petition (03/07/2014)

NATURAL GAS – Securities

Piedmont Natural Gas Company, Inc. -- G-9, SUB 648; Order Granting Authority to Issue and Sell Securities (04/24/2014)

RENEWABLE ENERGY THERMAL

RENEWABLE ENERGY THERMAL – Filings Due Per Order

Midtown Development Associates, LLC -- RET-35, SUB 0; Order Accepting Registration of New Renewable Energy Facility (12/08/2014)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS

SMALL POWER PRODUCERS – Cancellation of Certificate

ORDER CANCELLING CERTIFICATE AND REGISTRATION STATEMENT AND CLOSING DOCKET

Orders Issued

Company	Docket No.	Date
Brenden Solar, LLC	SP-2542, SUB 0	(03/18/2014)
Colin Solar, LLC	SP-2543, SUB 0	(03/18/2014)
Cooleemee Farm, LLC	SP-2432, SUB 0	(03/18/2014)
Dellenger Catawba Farm, LLC	SP-2946, SUB 0	(03/18/2014)
Elmwood Solar, LLC	SP-2509, SUB 0	(02/14/2014)
Jaren Solar, LLC	SP-2157, SUB 0	(03/18/2014)
Miles Solar, LLC	SP-2565, SUB 0	(03/18/2014)
Morgan Solar, LLC	SP-2570, SUB 0	(03/18/2014)

Elizabeth City Solar, LLC -- SP-3412, SUB 0; Order Canceling Certificate and Requiring Further Publication of Notice (06/27/2014)

Elizabeth Solar, LLC -- SP-3431, SUB 0; Order Allowing Withdrawal of Application, Cancelling Certificate of Public Convenience and Necessity and Closing Docket (12/05/2014)

Holiday Farm, LLC -- SP-2714, SUB 0; Order Cancelling Certificate and Registration and Closing Docket (06/27/2014)

Katherine Solar, LLC -- SP-2569, SUB 0; Order Allowing Withdrawal of Application, Canceling CPCN and Closing Docket (10/10/2014)

Mainor Farm, LLC -- SP-3445, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (12/15/2014)

Marston Farm, LLC -- SP-3415, SUB 0; Order Allowing Withdrawal of Application, Cancelling Certificate of Public Convenience and Necessity and Closing Docket (09/25/2014)

RJ Solar, LLC -- SP-2572, SUB 0; Order Allowing Withdrawal of Application, Canceling CPCN and Closing Docket (10/10/2014)

SoINCPower5, LLC -- SP-3717, SUB 0; Order Canceling Certificate and Requiring Publication of Notice (08/19/2014)

SunEnergy 1, LLC -- SP-751,
SUB 12; Order Cancelling Certificate and Closing Docket (03/14/2014)
SUB 13; Order Cancelling Certificate and Requiring Publication of Notice (08/19/2014)
SUB 18; Order Cancel. Certificate and Requir. Further Publication of Notice (06/27/2014)

Tripp Solar, LLC – SP-4286, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (12/15/2014)

Warsaw Farm, LLC -- SP-2526, SUB 0; Order Canceling Certificate and Registration and Requiring Further Publication of Notice (06/02/2014)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCERS -- Certificate

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued

Company	Docket No.	Date
Apple, Inc.	SP-1642, SUB 3	(09/19/2014)
Aquenergy Systems, Inc.	SP-451, SUB 2	(02/05/2014)
Auten Road Farm, LLC	SP-3173, SUB 0	(10/14/2014)
Bennett; Mary B.	SP-299, SUB 1	(06/12/2014)
Bethel Price Solar, LLC	SP-3190, SUB 1	(03/25/2014)
Bladenboro Solar, LLC	SP-2741, SUB 1	(04/16/2014)
Byers; Clayton	SP-3704, SUB 0	(06/09/2014)
Cape Fear Solar I, LLC	SP-2385, SUB 1	(02/05/2014)
Castelow Solar Farm, LLC	SP-3722, SUB 0	(06/17/2014)
Chambless; Lloyd	SP-3520, SUB 0	(10/13/2014)
Colonial Eagle Solar, LLC	SP 4305, SUB 0	(12/19/2014)
Cooley; Wayne S.	SP-3116, SUB 1	(01/28/2014)
County Home Solar Center, LLC	SP-3951, SUB 0	(12/18/2014)
Crews; Agnes	SP-3788, SUB 0	(10/13/2014)
CS Murphy Point, LLC	SP-1128, SUB 1	(09/09/2014)
Dobbins Mill Farm, LLC	SP-2893, SUB 0	(01/21/2014)
ESA Renewables IV, LLC	SP-1565, SUB 11	(12/17/2014)
Estes Express Lines, Inc.	SP-3880, SUB 0	(12/17/2014)
Filippini; David	SP-3231, SUB 1	(01/28/2014)
Harvest Beulaville, LLC	SP-3550, SUB 0	(05/30/2014)
HCE Johnston I, LLC	SP-3364, SUB 0	(02/27/2014)
Hermosillo; Enrique	SP-3339, SUB 0	(02/12/2014)
Highwater Solar II, LLC	SP-4065, SUB 0	(12/22/2014)
Holstein Holdings, LLC	SP-2758, SUB 1	(02/07/2014)
Honeycutt; Travis CB	SP-379, SUB 1	(06/30/2014)
Industrial Centers, LLC	SP-3109, SUB 0	(01/10/2014)
Innovative Solar 23, LLC	SP-3289, SUB 1	(02/10/2014)
Innovative Solar 26, LLC	SP-3290, SUB 1	(02/07/2014)
Johnson Breeders, Inc.	SP-3253, SUB 1	(07/23/2014)
Kempter; Bryan	SP-3453, SUB 0	(10/13/2014)
Lockhart BioEnergy, LLC	SP-3894, SUB 0	(09/10/2014)
Long; Janet and John R.	SP-3079, SUB 1	(03/11/2014)
McCaskey Solar Farm, LLC	SP-3322, SUB 0	(02/07/2014)
McFarland Septic, LLC	SP-3277, SUB 1	(03/28/2014)
New Hill Solar, LLC	SP-4636, SUB 0	(12/22/2014)
Nichols; Patricia C.	SP-3074, SUB 1	(03/06/2014)
Pamlico Partners Solar, LLC	SP-2999, SUB 1	(06/17/2014)
Parker; Leon	SP-3523, SUB 0	(10/13/2014)
Peanut Farm, LLC	SP-2720, SUB 0	(08/21/2014)

ORDERS AND DECISIONS LISTED

ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
Perdue Farms, Inc.	SP-3853, SUB 0	(10/13/2014)
Potluck Power Company	SP-405, SUB 1	(06/30/2014)
Pricket; Dixie-Marree	SP-3684, SUB 0	(06/05/2014)
QVC, Inc.	SP-362, SUB 3	(04/17/2014)
RayLen Vineyards Solar, LLC	SP-3468, SUB 0	(04/01/2014)
REI 2, LLC	SP-2014, SUB 1	(05/05/2014)
SAS Institute, Inc.	SP-328, SUB 5	(08/21/2014)
Sensenig; Cliff	SP-2588, SUB 0	(05/13/2014)
South Winston Farm, LLC	SP-3168, SUB 0	(08/27/2014)
Terry; Mark R.	SP-3728, SUB 1	(09/10/2014)
W.E. Partners V, LLC	SP-2857, SUB 0	(03/12/2014)
Weston; Jon B.	SP-3388, SUB 1	(06/30/2014)
Windsor Cooper Hill Solar, LLC	SP-3189, SUB 1	(04/07/2014)
Yadkin 601 Farm, LLC	SP-3145, SUB 0	(07/22/2014)
Zirpolo; Michael	SP-2802, SUB 0	(03/11/2014)

Bennett; Mary B. -- SP-299, SUB 1; Errata Order (06/25/2014)

HCE Johnston I, LLC -- SP-3364, SUB 0; Errata Order (07/07/2014)

Innovative Solar 14, LLC -- SP-2205, SUB 1; Order Amending Registration of New Renewable Energy Facility (04/14/2014)

Innovative Solar 15, LLC -- SP-2153, SUB 1; Order Amending Registration of New Renewable Energy Facility (05/12/2014)

Mill Solar 1, LLC -- SP-2142, SUB 0; Order Amending Registration of New Renewable Energy Facility (04/14/2014)

RockTenn CP, LLC -- SP-2973, SUB 0; Order Accepting Registration of Renewable Energy Facility (02/20/2014)

Scenic Valley Dairy, LLC -- SP-3229, SUB 0; Order Accepting Registration of Renewable Energy Facility (06/04/2014); Errata Order (07/16/2014)

Vickers Farm, LLC -- SP-2370, SUB 0; Errata Order (01/24/2014)

Warsaw Farm, LLC -- SP-2526, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (08/26/2014)

W.E. Partners II, LLC – SP-882, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (08/01/2014); Errata Order (08/08/2014)

W.E. Partners IV, LLC -- SP-1155, SUB 1; Order Accepting Amended Registration of New Renewable Energy Facility (08/05/2014)

W.E. Partners V, LLC – SP-2857, SUB 0; Order Accepting Amended Registration of New Renewable Energy Facility (08/05/2014)

ORDERS AND DECISIONS LISTED

ORDER ALLOWING WITHDRAWAL OF APPLICATION AND CLOSING DOCKET(S)

Orders Issued

Company	Docket No.	Date
Apollo Solar, LLC	SP-3486, SUB 0	(09/23/2014)
Calvin Solar, LLC	SP-2779, SUB 0	(03/18/2014)
Carolina Solar Energy II, LLC	SP-2363, SUB 13	(09/23/2014)
Cook 21 Farm, LLC	SP-3169, SUB 0	(01/14/2014)
Corbin Solar, LLC	SP-2155, SUB 0	(03/18/2014)
Cougar Solar, LLC	SP-2559, SUB 0	(01/14/2014)
East Burke Farm, LLC	SP-3157, SUB 0	(04/23/2014)
ESA Renewables X, LLC	SP-1609, SUB 0	(09/12/2014)
	SP-1609, SUB 1	
Go Solar of Columbus LLC	SP-3912, SUB 0	(09/11/2014)
	SP-4174, SUB 0	
Haley Barnes Investments LLP	SP-3913, SUB 0	(09/11/2014)
	SP-4175, SUB 0	
Jensen Solar, LLC	SP-2850, SUB 0	(09/25/2014)
Katelynne Solar, LLC	SP-2162, SUB 0	(09/23/2014)
KC Byrd Electrical Contractor, Inc.	SP-3804, SUB 0	(07/23/2014)
	SP-669, SUB 2	(07/23/2014)
	SP-669, SUB 3	(07/23/2014)
Kristen Energy, LLC	SP-1811, SUB 0	(03/18/2014)
	SP-1811, SUB 1	
Lillie Solar, LLC	SP-1938, SUB 0	(03/18/2014)
Louisburg Solar LLC	SP-2942, SUB 0	(05/21/2014)
Madison Fulp Farm, LLC	SP-2944, SUB 0	(04/23/2014)
Maverick Solar, LLC	SP-2566, SUB 0	(09/23/2014)
Pine Gate Holdings, LLC	SP-3834, SUB 16	(09/23/2014)
	SP-3834, SUB 21	(09/23/2014)
	SP-3834, SUB 27	(09/12/2014)
	SP-3834, SUB 38	(09/23/2014)
Prospect Solar 2, LLC	SP-3834, SUB 32	(12/16/2014)
	SP-4448, SUB 0	
Roanoke Rapids Solar LLC	SP-3264, SUB 0	(07/10/2014)
Salome Solar, LLC	SP-4141, SUB 0	(12/15/2014)
Spartan Solar, LLC	SP-2215, SUB 0	(03/18/2014)
SunEnergy 1, LLC	SP-751, SUB 16	(02/06/2014)
	SP-751, SUB 17	(09/23/2014)
Teri Solar, LLC	SP-2852, SUB 0	(09/23/2014)
Washington Springs Road Solar, LLC	SP-3307, SUB 0	(08/19/2014)

SMALL POWER PRODUCERS – Certificate *(Continued)*

Angus Holdings, LLC -- SP-3794, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (12/15/2014)

Austin Solar, LLC -- SP-2778, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (10/10/2014)

Binks Solar, LLC -- SP-2679, SUB 0; Order Allowing Withdrawal of Application, Canceling CPCN and Closing Docket (10/10/2014)

Carolina Solar Energy II, LLC – SP-2363, SUB 5; Order Allowing Withdrawal of Application and Registration (03/14/2014)

Prospect Solar 1, LLC – SP-4444, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (12/15/2014)

Rhubarb One, LLC -- SP-3889, SUB 0; Order Allowing Withdrawal of Application, Cancelling CPCN and Closing Docket (12/15/2014)

ORDER AMENDING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION STATEMENT

Orders Issued

Company	Docket No.	Date
Angier Farm, LLC	SP-2301, SUB 0	(01/21/2014)
Ariel Solar, LLC	SP-3649, SUB 0	(10/24/2014)
Beth Solar, LLC	SP-1939, SUB 0	(10/10/2014)
Big Boy Solar, LLC	SP-1814, SUB 0	(10/10/2014)
	SP-1814, SUB 1	
Biscoe Solar, LLC	SP-2165, SUB 0	(09/19/2014)
Charlie Solar, LLC	SP-2059, SUB 0	(04/04/2014)
		(10/10/2014)
Cornstalk Solar, LLC	SP-3811, SUB 0	(12/04/2014)
Downs Farm Solar, LLC	SP 4044, SUB 0	(12/04/2014)
Fresh Air Energy II, LLC	SP-2665, SUB 0	(01/10/2014)
	SP-2665, SUB 1	(01/10/2014)
	SP-2665, SUB 2	(01/10/2014)
	SP-2665, SUB 4	(01/10/2014)
	SP-2665, SUB 5	(01/10/2014)
	SP-2665, SUB 6	(01/10/2014)
	SP-2665, SUB 13	(01/10/2014)
	SP-2665, SUB 14	(01/10/2014)
	SP-2665, SUB 15	(01/10/2014)
Fresh Air Energy XIII, LLC	SP-3693, SUB 0	(09/19/2014)
Fresh Air Energy XIV, LLC	SP-3694, SUB 0	(09/19/2014)
HXNAir Solar One, LLC	SP-3286, SUB 0	(12/04/2014)
Lotus Solar, LLC	SP-1813, SUB 0	(10/10/2014)
	SP-1813, SUB 1	
Redmon Solar Farm, LLC	SP-2662, SUB 0	(06/02/2014)
Selma Solar, LLC	SP-2167, SUB 0	(09/19/2014)
Shankle Solar Center, LLC	SP-2311, SUB 0	(10/10/2014)
SoINCPower1, LLC	SP-2910, SUB 2	(09/19/2014)

ORDER AMENDING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION STATEMENT

Orders Issued *(Continued)*

Company	Docket No.	Date
SoINCPower2, LLC	SP-3220, SUB 0	(09/19/2014)
Soluga Farms I, LLC	SP-2462, SUB 0	(01/15/2014)
Soluga Farms II, LLC	SP-2463, SUB 0	(01/15/2014)
Turkey Branch Solar, LLC	SP-2168, SUB 0	(09/19/2014)

Bearpond Solar Center, LLC -- SP-2313, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (09/23/2014)

Dobbins Mill Farm, LLC -- SP-2893, SUB 0; Order Amending Certificate of Public Convenience and Necessity (04/15/2014)

Graham Solar Center, LLC -- SP-2309, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (09/23/2014)

Pamlico Partners Solar LLC -- SP-2999, SUB 0; Order Amending Certificate of Public Convenience and Necessity (01/13/2014)

QVC, Inc. -- SP-362, SUB 2; Order Amending Certificate of Public Convenience and Necessity (04/10/2014)

ORDER ISSUING CERTIFICATE

Orders Issued

Company	Docket No.	Date
Ahoskie FIA Solar, LLC	SP-4259, SUB 0	(11/26/2014)
Ahoskie 561 Solar, LLC	SP-4261, SUB 0	(11/26/2014)
Aulander Hwy 42 Solar, LLC	SP-4258, SUB 0	(12/09/2014)
Balsam Solar, LLC	SP-3758, SUB 0	(10/07/2014)
Bethel Pitt Road Solar, LLC	SP-3240, SUB 0	(04/01/2014)
Bladenboro Solar, LLC	SP-2741, SUB 0	(01/28/2014)
Butternut Solar Farm, LLC	SP-4326, SUB 0	(12/02/2014)
CBC Alternative Energy, LLC	SP-1405, SUB 2	(01/22/2014)
Cedar Solar, LLC	SP-3295, SUB 0	(10/07/2014)
Chocowinity Farm, LLC	SP-4192, SUB 0	(11/26/2014)
Colerain Hwy 45 Solar, LLC	SP-4102, SUB 0	(11/26/2014)
EC Okisko Solar, LLC	SP-4006, SUB 0	(11/12/2014)
Elizabeth City Solar, LLC	SP-3412, SUB 0	(06/02/2014) (09/09/2014)
Elm Solar, LLC	SP-3754, SUB 0	(10/14/2014)
Everetts Solar, LLC	SP-3441, SUB 0	(05/20/2014)
Floyd Road Solar Farm, LLC	SP-4324, SUB 0	(11/26/2014)
Hector Farm, LLC	SP-4194, SUB 0	(11/26/2014)
Hickory Solar, LLC	SP-3755, SUB 0	(09/30/2014)
Jamesville Pulp Mill Solar, LLC	SP-4231, SUB 0	(12/22/2014)
Kilford Solar, LLC	SP-3209, SUB 0	(03/20/2014)

ORDER ISSUING CERTIFICATE

Orders Issued (Continued)

Company	Docket No.	Date
Long Farm 46 Solar, LLC	SP-4313, SUB 0	(11/26/2014)
Maxton Biogas, LLC	SP-2837, SUB 0	(02/20/2014)
MC1 Solar Farm, LLC	SP-4327, SUB 0	(11/26/2014)
MC2 Solar Farm, LLC	SP-4314, SUB 0	(11/26/2014)
Mill Pond Solar, LLC	SP-4061, SUB 0	(11/12/2014)
NOVI Carolina Digester I, LLC	SP-3185, SUB 0	(02/05/2014)
Phelps 158 Solar Farm, LLC	SP-4319, SUB 0	(11/26/2014)
Poplar Solar, LLC	SP-3757, SUB 0	(10/07/2014)
		(10/14/2014)
River Road Solar, LLC	SP-4260, SUB 0	(11/26/2014)
Sampson Renewable Energy, LLC	SP-2353, SUB 0	(11/26/2014)
Seagrove Farm, LLC	SP-4197, SUB 0	(11/26/2014)
Shawboro Meads Solar, LLC	SP-4232, SUB 0	(11/12/2014)
Shiloh Hwy 1108 Solar, LLC	SP-4103, SUB 0	(11/04/2014)
SoINCPower10, LLC	SP-4312, SUB 0	(11/26/2014)
SunEnergy 1, LLC		
(Pasquotank Co.)	SP-751, SUB 13	(10/21/2014)
(Washington Co.)	SP-751, SUB 18	(08/27/2014)
(Conetoe, NC)	SP-751, SUB 21	(01/15/2014)
(Leggett, NC)	SP-751, SUB 22	(01/08/2014)
(Windsor, NC)	SP-751, SUB 23	(01/08/2014)
Warsaw Farm, LLC	SP-2526, SUB 0	(08/06/2014)
Weldon Trueblood Solar, LLC	SP-4062, SUB 0	(11/12/2014)

Auten Road Farm, LLC **--** SP-3173, SUB 0; Recommended Order Granting Certificate (10/14/2014)

Dobbins Mill Farm, LLC **--** SP-2893, SUB 0 Recommended Order Granting Certificate with Conditions (01/21/2014)

Howell Midland Farm, LLC **--** SP-3378, SUB 0 Recommended Order Granting Certificate with Conditions (09/29/2014)

SolarGreen Eco-Industrial Solar Park 1, LLC **--** SP-3545, SUB 0; Order Issuing Certificate of New Renewable Energy Facility (09/18/2014)

South Winston Farm, LLC **--** SP-3168, SUB 0 Recommended Order Granting Certificate with Conditions (08/27/2014); Errata Order (08/27/2014)

Sunbury McCoy Lane Solar, LLC **--** SP-3353, SUB 0; Recommended Order Granting Certificate (08/12/2014)

Yadkin 601 Farm, LLC **--** SP-3145, SUB 0; Recommended Order Granting Certificate and Accepting Registration (07/11/2014)

ORDERS AND DECISIONS LISTED

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued

Company	Docket No.	Date
ABD Farm Solar, LLC	SP-2363, SUB 15	(10/24/2014)
	SP-4345, SUB 0	
Allen Solar Farm, LLC	SP-3413, SUB 0	(05/20/2014)
Amigo Farm, LLC	SP-4293, SUB 0	(12/18/2014)
Andrew Solar, LLC	SP-3432, SUB 0	(07/28/2014)
Angus Holdings LLC	SP-3794, SUB 0	(09/18/2014)
Apple One, LLC	SP-3466, SUB 0	(07/23/2014)
Ariel Solar, LLC	SP-3649, SUB 0	(08/13/2014)
Atkinson Farm, LLC	SP-3831, SUB 0	(09/03/2014)
Aulander Solar LLC	SP-2993, SUB 0	(09/23/2014)
Ayrshire Holdings, LLC	SP-3051, SUB 0	(05/28/2014)
	SP-3051, SUB 1	
Azalea Solar, LLC	SP-3814, SUB 0	(10/29/2014)
Battleboro Farm, LLC	SP-3284, SUB 0	(04/22/2014)
Battleboro Solar, LLC	SP-3606, SUB 0	(08/06/2014)
Bearford Farm, LLC	SP-3902, SUB 0	(09/18/2014)
Bearford Solar II, LLC	SP-3797, SUB 0	(10/14/2014)
Beaver Dam Solar LLC	SP-2661, SUB 0	(10/21/2014)
	SP-2661, SUB 1	
	SP-4467, SUB 0	
Berkeley Farm, LLC	SP-3380, SUB 0	(06/30/2014)
Bethel Farm, LLC	SP-3414, SUB 0	(05/20/2014)
Bethel Solar LLC	SP-2538, SUB 0	(05/20/2014)
	SP-2538, SUB 1	
BG Stewart Solar Farm, LLC	SP-3360, SUB 0	(10/21/2014)
Bizzell Church Solar 3, LLC	SP-3834, SUB 15	(10/14/2014)
	SP-4322, SUB 0	
Blueberry One, LLC	SP-3037, SUB 0	(03/27/2014)
Boaz Farm Solar, LLC	SP-2363, SUB 22	(10/29/2014)
	SP-4476, SUB 0	
British Farm, LLC	SP-3450, SUB 0	(05/20/2014)
Broadridge Solar, LLC	SP-3834, SUB 48	(11/12/2014)
	SP-4451, SUB 0	
Bunch Solar Farm, LLC	SP-3225, SUB 0	(03/06/2014)
Cabaniss Farm, LLC	SP-3829, SUB 0	(09/03/2014)
Calypso Farm, LLC	SP-3716, SUB 0	(09/09/2014)
Calypso Solar LLC	SP-2042, SUB 1	(10/14/2014)

ORDERS AND DECISIONS LISTED

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
Carolina Solar Energy II, LLC		
(Martin Co.)	SP-2363, SUB 3	(01/15/2014)
(Hertford Co.)	SP-2363, SUB 4	(04/15/2014)
(adjacent to substation #0433)	SP-2363, SUB 6	(04/01/2014)
(Nash Co.)	SP-2363, SUB 7	(05/20/2014)
(Northampton County)	SP-2363, SUB 17	(10/29/2014)
(Bertie County	SP-2363, SUB 18	(09/18/2014)
Caswell Solar, LLC	SP-4280, SUB 0	(12/02/2014)
Cattail Solar, LLC	SP-3813, SUB 0	(10/29/2014)
Chei Solar, LLC	SP-3433, SUB 0	(12/18/2014)
Chocowinity Solar, LLC	SP-3183, SUB 0	(04/15/2014)
Cirrus Solar, LLC	SP-2988, SUB 0	(02/20/2014)
Clark Brothers LLC	SP-3685, SUB 0	(09/18/2014)
Cline Solar, LLC	SP-3834, SUB 11	(10/14/2014)
	SP-4315, SUB 0	
Clipperton Holdings, LLC	SP-3700, SUB 0	(09/09/2014)
Coats Solar, LLC	SP-3834, SUB 22	(11/12/2014)
	SP-4402, SUB 0	
Cohen Farm Solar, LLC	SP-2363, SUB 19	(12/22/2014)
	SP-4472, SUB 0	
Columbo Farm, LLC	SP-3830, SUB 0	(09/03/2014)
Cornstalk Solar, LLC	SP-3811, SUB 0	(10/14/2014)
Cottonwood Solar, LLC	SP-3614, SUB 0	(10/29/2014)
Creech Solar 2, LLC	SP-3834, SUB 47	(11/12/2014)
	SP-4450, SUB 0	
Crestwood Solar Center, LLC	SP-3110, SUB 0	(02/20/2014)
Crockett Farm, LLC	SP-3146, SUB 0	(08/06/2014)
Davidson Solar, LLC	SP-4005, SUB 0	(10/07/2014)
Delco Farm, LLC	SP-3832, SUB 0	(09/03/2014)
Dragstrip Farm, LLC	SP-2892, SUB 0	(01/28/2014)
Durham Solar, LLC	SP-3834, SUB 18	(10/14/2014)
	SP-4316, SUB 0	
Edgecombe Mercer Farm, LLC	SP-3239, SUB 0	(03/06/2014)
Elizabeth Solar, LLC	SP-3431, SUB 0	(07/11/2014)
ESA Benson Solar NC, LLC	SP-3176, SUB 0	(11/26/2014)
ESA Four Oaks NC 1, LLC	SP-2611, SUB 1	(03/27/2014)
ESA Henderson NC, LLC	SP-3540, SUB 0	(10/29/2014)
ESA Princeton NC, LLC	SP-3063, SUB 0	(05/28/2014)
Exum Farm Solar, LLC	SP-2363, SUB 20	(10/29/2014)
	SP-4473, SUB 0	

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued *(Continued)*

Company	Docket No.	Date
Faison Farm, LLC	SP-3659, SUB 0	(10/21/2014)
FLS Solar 230, LLC	SP-2863, SUB 0	(08/06/2014)
FLS Solar 260, LLC	SP-2904, SUB 0	(06/16/2014)
Foxfire Farm, LLC	SP-3377, SUB 0	(04/28/2014)
Franklinton Solar LLC	SP-3798, SUB 0	(09/23/2014)
Freemont Solar Center, LLC	SP-3953, SUB 0	(12/18/2014)
Fresh Air Energy II, LLC		
(Elm City, NC)	SP-2665, SUB 9	(05/13/2014)
(N. Whitakers, NC)	SP-2665, SUB 10	(02/26/2014)
(Roanoke Rapids, NC)	SP-2665, SUB 11	(06/30/2014)
(Claremont, NC)	SP-2665, SUB 12	(02/20/2014)
(Lexington, NC)	SP-2665, SUB 16	(03/20/2014)
(Williamston, NC)	SP-2665, SUB 17	(03/20/2014)
(High Shoals, NC)	SP-2665, SUB 18	(04/22/2014)
(Red Hill Church Rd.-Harnett Co.)	SP-2665, SUB 19	(04/22/2014)
(Eastover, NC)	SP-2665, SUB 20	(06/02/2014)
(near Murfreesboro- Hertford Co.-)	SP-2665, SUB 22	(09/09/2014)
(off Highway 48, Northampton Co.)	SP-2665, SUB 23	(07/23/2014)
(East of Benthall Bridge Rd., Hertford Co.)	SP-2665, SUB 24	(07/23/2014)
(1029 NC Hwy. 11 South, Hertford Co.)	SP-2665, SUB 25	(07/23/2014)
(Elon, NC)	SP-2665, SUB 26	(07/23/2014)
(1914 West Main St., Northampton Co.)	SP-2665, SUB 27	(07/11/2014)
(Robersonville, NC)	SP-2665, SUB 29	(09/18/2014)
(Asheboro, NC)	SP-2665, SUB 31	(10/21/2014)
(6562 Caratoke Hwy-Currituck Co.)	SP-2665, SUB 33	(10/21/2014)
Gantt Farm, LLC	SP-3181, SUB 0	(03/27/2014)
Garland Farm, LLC	SP-3656, SUB 0	(08/06/2014)
Garysburg Solar LLC	SP-2996, SUB 0	(09/03/2014)
Gaston Solar LLC	SP-3102, SUB 0	(09/23/2014)
Gates Solar, LLC	SP-3201, SUB 0	(03/12/2014)
Germantown Solar, LLC	SP-3834, SUB 6 SP-4317, SUB 0	(10/14/2014)
Guernsey Holdings LLC	SP-3795, SUB 0	(09/18/2014)
Happy Solar, LLC	SP-4251, SUB 0	(12/22/2014)
Hardison Farm Solar, LLC	SP-2363, SUB 8 SP-4340, SUB 0	(10/14/2014)
Harvest Solar 1, LLC	SP-4001, SUB 0	(11/26/2014)
Haywood Farm Solar, LLC	SP-2363, SUB 12 SP-4344, SUB 0	(11/04/2014)
Hemlock Solar, LLC	SP-3548, SUB 0	(10/29/2014)
Hereford Holdings, LLC	SP-3888, SUB 0	(10/07/2014)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued (Continued)

Company	Docket No.	Date
Hew Fulton Farm, LLC	SP-4051, SUB 0	(12/18/2014)
Highland Solar Center, LLC	SP-3107, SUB 0	(02/20/2014)
Highwater Solar I, LLC	SP-3675, SUB 0	(09/09/2014)
Hoffland Environmental, Inc.	SP-2950, SUB 0	(02/20/2014)
Hogler Holdings, LLC	SP-3655, SUB 0	(08/13/2014)
Husky Solar, LLC	SP-2848, SUB 0	(11/26/2014)
Hutchinson Farm, LLC	SP-1636, SUB 0	(08/13/2014)
HXNAir Solar One, LLC	SP-3286, SUB 0	(05/07/2014)
Infigen Energy US Development LLC	SP-4106, SUB 0	(10/29/2014)
	SP-4106, SUB 1	(12/18/2014)
	SP-4106, SUB 2	(12/18/2014)
Innovative Solar 6, LLC	SP-1724, SUB 2	(10/29/2014)
Innovative Solar 31, LLC	SP-3474, SUB 0	(08/13/2014)
Innovative Solar 33, LLC	SP-3615, SUB 0	(08/06/2014)
Innovative Solar 34, LLC	SP-3475, SUB 0	(08/06/2014)
Innovative Solar 37, LLC	SP-3617, SUB 0	(09/18/2014)
Innovative Solar 38, LLC	SP-3618, SUB 0	(09/18/2014)
Innovative Solar 40, LLC	SP-3619, SUB 0	(07/23/2014)
Innovative Solar 41, LLC	SP-3476, SUB 0	(09/18/2014)
Innovative Solar 42, LLC	SP-3477, SUB 0	(07/23/2014)
Innovative Solar 43, LLC	SP-3620, SUB 0	(09/18/2014)
Innovative Solar 44, LLC	SP-3692, SUB 0	(08/06/2014)
Innovative Solar 46, LLC	SP-3478, SUB 0	(09/18/2014)
Innovative Solar 47, LLC	SP-3621, SUB 0	(09/18/2014)
Innovative Solar 48, LLC	SP-3695, SUB 0	(08/06/2014)
Innovative Solar 53, LLC	SP-3687, SUB 0	(09/18/2014)
Innovative Solar 54, LLC	SP-3688, SUB 0	(09/18/2014)
Innovative Solar 55, LLC	SP-3698, SUB 0	(08/06/2014)
Innovative Solar 63, LLC	SP-3895, SUB 0	(12/18/2014)
Innovative Solar 64, LLC	SP-3699, SUB 0	(08/13/2014)
Innovative Solar 67, LLC	SP-3689, SUB 0	(08/13/2014)
Innovative Solar 68, LLC	SP-3690, SUB 0	(08/13/2014)
Innovative Solar 69, LLC	SP-3897, SUB 0	(09/18/2014)
Innovative Solar 71, LLC	SP-3898, SUB 0	(10/07/2014)
Innovative Solar 72, LLC	SP-3899, SUB 0	(09/18/2014)
Jakana Solar LLC	SP-2498, SUB 0	(01/22/2014)
	SP-2498, SUB 1	
Jamesville Solar LLC	SP-3234, SUB 0	(09/23/2014)
Kalish Farm Solar, LLC	SP-2363, SUB 14	(10/29/2014)
	SP-4470, SUB 0	
Keen Farm, LLC	SP-3671, SUB 0	(08/06/2014)

ORDERS AND DECISIONS LISTED

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued (Continued)

Company	Docket No.	Date
Kelly Solar, LLC	SP-3834, SUB 45 SP-4454, SUB 0	(11/26/2014)
Kennedy Solar, LLC	SP-3784, SUB 0	(11/26/2014)
Kenneth Solar, LLC	SP-4249, SUB 0	(12/18/2014)
Kim Solar, LLC	SP-3436, SUB 0	(07/28/2014)
Kinston Davis Farm, LLC	SP-3379, SUB 0	(04/22/2014)
Kirkwall Holdings, LLC	SP-3337, SUB 0	(07/24/2014)
Kojak Farm, LLC	SP-4049, SUB 0	(11/04/2014)
Lake Solar Center, LLC	SP-3106, SUB 0	(01/22/2014)
Lang Solar Farm, LLC	SP-3405, SUB 0	(07/23/2014)
Langdon Solar Farm, LLC	SP-3591, SUB 0	(09/24/2014)
Lanier Solar, LLC	SP-3720, SUB 0	(08/13/2014)
Laurel Hill Solar, LLC	SP-3834, SUB 5 SP-4318, SUB 0	(10/21/2014)
Lewiston Solar LLC	SP-2499, SUB 1	(06/23/2014)
Lillington Solar, LLC	SP-4025, SUB 0	(10/21/2014)
Longhorn Holdings, LLC	SP-3336, SUB 0	(04/15/2014)
Louisburg Solar, LLC	SP-2942, SUB 1	(09/09/2014)
Lumbee Enterprise Development, Inc.	SP-2657, SUB 0 SP-2657, SUB 1	(04/15/2014)
Mainor Farm, LLC	SP-3445, SUB 0	(05/13/2014)
Manway Solar, LLC	SP-1979, SUB 1	(08/27/2014)
Mariposa Solar Center, LLC	SP-3104, SUB 0	(01/22/2014)
Marston Farm, LLC	SP-3415, SUB 0	(05/13/2014)
Mason Solar Center, LLC	SP-3132, SUB 0	(01/28/2014)
Maxton Solar 1, LLC	SP-3834, SUB 23 SP-4287, SUB 0	(10/21/2014)
McBride Place Energy, LLC	SP-3096, SUB 0	(11/26/2014)
McCullen Solar, LLC	SP-3871, SUB 0	(09/30/2014)
McDougald Solar, LLC	SP-3834, SUB 34 SP-4443, SUB 0	(10/21/2014)
McGoogan Farm, LLC	SP-3403, SUB 0	(10/21/2014)
Meadowbrook Solar, LLC	SP-4080, SUB 0	(11/26/2014)
Meares Solar Center, LLC	SP-3955, SUB 0	(12/18/2014)
Melinda Solar, LLC	SP-3874, SUB 0	(12/18/2014)
Meriwether Farm, LLC	SP-4269, SUB 0	(11/26/2014)
Millikan Farm, LLC	SP-3382, SUB 0	(05/13/2014)
Misenheimer Farm, LLC	SP-3381, SUB 0	(05/13/2014)
Modlin Farm Solar, LLC	SP-2363, SUB 9 SP-4341, SUB 0	(10/14/2014)
Monroe Moore Farm, LLC	SP-3490, SUB 0	(07/11/2014)
Moorings Farm 2, LLC	SP-3672, SUB 0	(08/06/2014)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Morgan Farm, LLC	SP-3562, SUB 0	(07/23/2014)
Morgan Solar, LLC	SP-2570, SUB 0	(02/20/2014)
Mount Olive I, LLC	SP-3701, SUB 0	(09/23/2014)
	SP-3701, SUB 1	(09/23/2014)
	SP-3701, SUB 2	(12/18/2014)
Mt. Olive Solar 1, LLC	SP-3156, SUB 0	(10/14/2014)
Nan Solar Center, LLC	SP-3131, SUB 0	(04/28/2014)
Nash 97 Solar, LLC	SP-3834, SUB 0	(10/14/2014)
	SP-4216, SUB 0	
Nitro Solar, LLC	SP-3438, SUB 0	(07/11/2014)
North Nash Farm, LLC	SP-3669, SUB 0	(08/13/2014)
North Selma Solar LLC	SP-4024, SUB 0	(10/14/2014)
North Siler Farm, LLC	SP-3666, SUB 0	(08/13/2014)
Old Pageland-Monroe Road Solar Farm, LLC	SP-3957, SUB 0	(12/02/2014)
Oxford Solar 1, LLC	SP-3834, SUB 26	(11/12/2014)
	SP-4403, SUB 0	
Palmetto Solar, LLC	SP-3473, SUB 0	(11/04/2014)
Peach Solar, LLC	SP-3834, SUB 33	(10/21/2014)
	SP-4441, SUB 0	
Peanut Market Farm Solar, LLC	SP-2363, SUB 10	(11/12/2014)
	SP-4342, SUB 0	
Pinewood Solar Center, LLC	SP-3103, SUB 0	(01/15/2014)
Pit 64 Farm, LLC	SP-3673, SUB 0	(08/13/2014)
Pollocksville Solar LLC	SP-4026, SUB 0	(10/14/2014)
Prease Farm Solar, LLC	SP-2363, SUB 23	(10/29/2014)
	SP-4475, SUB 0	
Prospect Solar 1, LLC	SP-3834, SUB 31	(10/21/2014)
	SP-4444, SUB 0	
Quincy Solar, LLC	SP-3430, SUB 0	(07/11/2014)
Rhubarb One, LLC	SP-3889, SUB 0	(10/07/2014)
Roady Lane Farm, LLC	SP-3255, SUB 0	(03/27/2014)
Rutherford Farm, LLC	SP-2722, SUB 0	(03/20/2014)
Sandy Ridge Solar Farm	SP-3026, SUB 0	(03/06/2014)
Sarah Solar, LLC	SP-3435, SUB 0	(07/11/2014)
Schell Solar Farm, LLC	SP-3416, SUB 0	(05/13/2014)
Seaboard Solar, LLC	SP-3155, SUB 0	(10/14/2014)
Sedberry Farm, LLC	SP-3828, SUB 0	(09/09/2014)
SID Solar I, LLC	SP-2843, SUB 0	(02/20/2014)
Siler 421 Farm, LLC	SP-4225, SUB 0	(11/04/2014)
Smith Solar Farm, LLC	SP-3561, SUB 0	(07/23/2014)
Smithfield Solar LLC	SP-4027, SUB 0	(10/14/2014)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued *(Continued)*

Company	Docket No.	Date
Snow Camp Solar, LLC	SP-3834, SUB 42 SP-4442, SUB 0	(11/26/2014)
SoINCPower1, LLC	SP-2910, SUB 4	(01/08/2014)
SoINCPower3, LLC	SP-4132, SUB 0	(11/04/2014)
SoINCPower4, LLC	SP-3035, SUB 0	(01/08/2014)
SoINCPower5, LLC	SP-3717, SUB 0	(10/21/2014)
Soluga Farms III, LLC	SP-3371, SUB 0	(07/11/2014)
Soluga Farms IV, LLC	SP-3590, SUB 0	(07/23/2014)
Sonne One, LLC	SP-3335, SUB 0	(04/15/2014)
Sonne Two LLC	SP-3376, SUB 0	(05/13/2014)
Soul City Solar, LLC	SP-3032, SUB 0	(08/13/2014)
South Louisburg Solar LLC	SP-3799, SUB 0	(09/23/2014)
Southerland Farm, LLC	SP-4107, SUB 0	(11/04/2014)
Spencer Farm, LLC	SP-3491, SUB 0	(07/11/2014)
Spicewood Solar Farm, LLC	SP-2399, SUB 0	(04/15/2014)
Spring Hope Solar 2, LLC	SP-3834, SUB 35 SP-4440, SUB 0	(11/12/2014)
Spring Valley Farm, LLC	SP-3931, SUB 0	(10/07/2014)
Spring Valley Farm 2, LLC	SP-3919, SUB 0	(09/30/2014)
Stagecoach Solar, LLC	SP-3031, SUB 0	(11/26/2014)
Statesville Solar, LLC	SP-3834, SUB 24 SP-4323, SUB 0	(10/14/2014)
Stephenson Farm Solar, LLC	SP-2363, SUB 11 SP-4343, SUB 0	(11/12/2014)
Stikeleather Farm, LLC	SP-3930, SUB 0	(09/30/2014)
Stone Solar Farm, LLC	SP-4046, SUB 0	(12/18/2014)
Stoneville Farm, LLC	SP-3492, SUB 0	(08/06/2014)
Sun-Devil Solar, LLC	SP-3876, SUB 0	(11/04/2014)
Sun-Power-System, Inc.	SP-3241, SUB 0	(06/30/2014)
Sweetgum Solar, LLC	SP-3756, SUB 0	(09/30/2014)
Tar Heel Solar, LLC	SP-4411, SUB 0	(12/02/2014)
Tarboro Farm, LLC	SP-3444, SUB 0	(05/13/2014)
Tarboro Solar LLC	SP-2943, SUB 0	(02/20/2014)
Tart Farm, LLC	SP-3670, SUB 0	(07/23/2014)
Thomas Solar 1, LLC	SP-3834, SUB 44 SP-4449, SUB 0	(11/12/2014)
Tiburon Holdings, LLC	SP-3890, SUB 0	(10/07/2014)
Tower Solar Center, LLC	SP-3105, SUB 0	(01/22/2014)
Tracy Solar, LLC	SP-3437, SUB 0	(07/28/2014)
Tripp Solar, LLC	SP-3834, SUB 25 SP-4286, SUB 0	(10/14/2014)

ORDER ISSUING CERTIFICATE AND ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

Orders Issued (Continued)

Company	Docket No.	Date
TWE Ahoskie Solar Project, LLC	SP-3833, SUB 0	(09/03/2014)
TWE Chocowinity Solar Project, LLC	SP-3515, SUB 0	(07/23/2014)
TWE Creswell Solar Project, LLC	SP-3512, SUB 0	(06/30/2014)
TWE Kelford Solar Project, LLC	SP-3511, SUB 0	(06/16/2014)
TWE Kinston Solar Project, LLC	SP-3513, SUB 0	(06/16/2014)
TWE Laurinburg Solar Project, LLC	SP-3604, SUB 0	(07/23/2014)
TWE New Bern Solar Project, LLC	SP-3514, SUB 0	(09/23/2014)
United Therapeutics Corporation	SP-393, SUB 1	(03/20/2014)
Vance Solar 1, LLC	SP-3834, SUB 1 SP-4288, SUB 0	(10/14/2014)
Vass Solar 2, LLC	SP-3834, SUB 17 SP-4399, SUB 0	(10/29/2014)
Vicksburg Solar, LLC	SP-3036, SUB 0	(08/27/2014)
Wadesboro Farm 3, LLC	SP-4557, SUB 0	(12/22/2014)
Weldon Solar LLC	SP-3259, SUB 0	(09/23/2014)
Wellons Farm, LLC	SP-3674, SUB 0	(07/23/2014)
West Salisbury Farm, LLC	SP-3251, SUB 0	(03/06/2014)
West Siler Farm, LLC	SP-3148, SUB 0	(03/27/2014)
Westside Solar Farm, LLC	SP-3214, SUB 0	(04/01/2014)
Whitakers Farm, LLC	SP-3147, SUB 0	(03/12/2014)
Wilkesboro Hydropower, LLC	SP-4092, SUB 0	(11/04/2014)
Williamston Solar, LLC	SP-2515, SUB 0 SP-2515, SUB 1	(01/22/2014)
Winding Oak Solar Center, LLC	SP-3952, SUB 0	(10/29/2014)
Windsor Solar LLC	SP-2500, SUB 0 SP-2500, SUB 1	(02/05/2014)
Winton Solar LLC	SP-2995, SUB 0	(04/28/2014)
Woodland Church Farm, LLC	SP-3404, SUB 0	(05/07/2014)
Woodland Solar LLC	SP-2994, SUB 0	(04/28/2014)
Woodland 258 Farm, LLC	SP-3167, SUB 0	(06/16/2014)
Yadkinville Solar, LLC	SP-4410, SUB 0	(12/02/2014)
ZV Solar 1, LLC	SP-3834, SUB 3 SP-4215, SUB 0	(10/07/2014)

SMALL POWER PRODUCERS – Certificate *(Continued)*

Aspen Solar, LLC -- SP-3428, SUB 0; Order Issuing Certificate of New Renewable Energy Facility (09/30/2014)

Chowan Jehu Road Solar, LLC -- SP-3628, SUB 0; Order Issuing Certificate for a New Renewable Energy Facility (10/21/2014)

Chowan Virginia Road Solar, LLC -- SP-3627, SUB 0; Order Issuing Certificate for a New Renewable Energy Facility (10/21/2014)

Gliden Jehu Solar, LLC -- SP-3652, SUB 0; Order Issuing Certificate for a New Renewable Energy Facility (10/21/2014)

Williamston Solar, LLC -- SP-2515, SUB 0; SP-2515, SUB 1; Errata Order (01/23/2014)

SMALL POWER PRODUCERS -- Complaint

Tyner Gliden Solar, LLC -- SP-3650, SUB 0; SP-3651, SUB 0; SP-3652, SUB 0; Order Dismissing Complaint and Closing Dockets *(Chowan Gliden Road Solar, LLC & Gliden Jehu Solar, LLC)* (08/04/2014)

SMALL POWER PRODUCERS – Filings Due Per Order or Rule

Black; Maria E. & William C. -- SP-2502, SUB 1; Order Canceling Registration and Closing Docket (10/01/2014)

Colloredo; Franchesca N. & Rudolf Colloredo-Mansfield -- SP-2533, SUB 1; Order Canceling Registration and Closing Docket (10/13/2014)

Degulis; Joseph M. -- SP-2513, SUB 1; Order Cancelling Registration and Closing Docket (09/29/2014)

Edenfield; George & Sharon -- SP-2487, SUB 0; Order Cancelling Registration and Closing Docket (09/29/2014)

Keesee; Susan H. & David W. -- SP-2343, SUB 1; Order Cancelling Registration Statement and Closing Docket (08/26/2014)

Keil; Matthew W. – SP-410, SUB 0; Order Cancelling Registration and Closing Docket (08/26/2014)

Lewiston Solar LLC -- SP-2499, SUB 0; Order Canceling Registration of New Renewable Energy Facility and Closing Docket (06/25/2014)

Poplar Solar, LLC -- SP-3757, SUB 0; Errata Order (10/15/2014)

Ray Family Farms, Inc. -- SP-1415, SUB 1; Order Canceling Registration and Closing Docket (10/13/2014)

Snow Hill Solar, LLC -- SP-2317, SUB 0; Order Canceling Registration and Closing Docket (12/09/2014)

Van Buren; Frank L. -- SP-2029, SUB 1; Order Canceling Registration and Closing Docket (10/01/2014)

Young; Russell & Leslie J. -- SP-1785, SUB 1; Order Canceling Registration and Closing Docket (10/13/2014)

SMALL POWER PRODUCERS – Name Change

Fresh Air energy II, LLC – SP-2665, SUB 21; Order Accepting Amendment (01/10/2014)

SMALL POWER PRODUCERS – Report of Proposed Construction

Pine Gate Holdings, LLC -- SP-3834,
SUB 40; Order Allowing Withdrawal of Report and Closing Docket (12/15/2014)
SUB 41; Order Allowing Withdrawal of Report and Closing Docket (10/10/2014)

Pleasant Grove Solar, LLC -- SP-3868, SUB 0; Order Allowing Withdrawal of Report and Closing Docket (11/20/2014)

SMALL POWER PRODUCERS – Sale/Transfer

ORDER TRANSFERRING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION

Orders Issued

Company	Docket No.	Date
Bearpond Solar Center, LLC		
(SunE Bearpond Lessee, LLC)	SP-2313, SUB 0 SP-4776, SUB 0	(11/26/2014)
Fresh Air Energy II, LLC		
(Fresh Air Energy IX, LLC)	SP-2665, SUB 2 SP-3556, SUB 0	(04/22/2014)
(Fresh Air Energy X, LLC)	SP-2665, SUB 13 SP-3558, SUB 0	(04/30/2014)
(Fresh Air Energy XI, LLC)	SP-2665, SUB 6 SP-3557, SUB 0	(04/30/2014)
(Fresh Air Energy XII, LLC)	SP-2665, SUB 9 SP-3691, SUB 0	(05/30/2014)
(Fresh Air Energy XIII, LLC)	SP-2665, SUB 0 SP-3693, SUB 0	(05/30/2014)
(Fresh Air Energy XIV, LLC)	SP-2665, SUB 15 SP-3694, SUB 0	(05/30/2014)
(Fresh Air Energy XV, LLC)	SP-2665, SUB 12 SP-3759, SUB 0	(06/13/2014)
(Fresh Air Energy XVI, LLC)	SP-2665, SUB 1 SP-3760, SUB 0	(08/19/2014)
(Fresh Air Energy XVII, LLC)	SP-2665, SUB 10 SP-4621, SUB 0	(12/05/2014)
(Fresh Air Energy XVIII, LLC)	SP-2665, SUB 17 SP-4623, SUB 0	(12/11/2014)
(Fresh Air Energy XX, LLC)	SP-2665, SUB 26 SP-4626, SUB 0	(12/11/2014)
(Fresh Air Energy XXI, LLC)	SP-2665, SUB 24 SP-4624, SUB 0	(12/11/2014)
(Fresh Air Energy XXII, LLC)	SP-2665, SUB 25 SP-4625, SUB 0	(12/11/2014)

ORDER TRANSFERRING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND REGISTRATION
Orders Issued *(Continued)*

Company	Docket No.	Date
Hoffland Environmental, Inc.		
(Legacy Biogas LLC)	SP-2950, SUB 0 SP-4131, SUB 0	(08/19/2014)
Shankle Solar Center, LLC		
(SunE Shankle Lessee, LLC)	SP-2311, SUB 0 SP-4796, SUB 0	(12/04/2014)
Siler Farm, LLC		
(Goldsboro Farm, LLC)	SP-1632, SUB 0 SP-3569, SUB 0	(04/23/2014)
SoINCPower1, LLC		
(SoINCPower5, LLC)	SP-2910, SUB 4 SP-3717, SUB 0	(06/03/2014)
(SoINCPower6, LLC)	SP-2910, SUB 0 SP-3719, SUB 0	(06/03/2014)

Beaver Dam Solar, LLC – SP-4467, SUB 0; SP-4687, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration Statement *(Rockingham Solar, LLC)* (11/20/2014)

Carolina Solar Energy II, LLC -- SP-2363,
- SUB 3; SP-4069, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration Statement *(Green Farm Solar, LLC)* (08/19/2014)
- SUB 4; SP-4044, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration Statement *(Downs Farm Solar, LLC)* (08/19/2014)
- SUB 6; SP-4221, SUB 0; Order Transferring Certificate of Public Convenience and Necessity and Registration Statement *(Simons Farm Solar, LLC)* (09/23/2014)

Catalyst Energy Corporation of Montgomery County – SP-84, SUB 0; SP-3230, SUB 0; Order Transfering Certificate of Public Convenience and Necessity *(EWP LLC)* (02/06/2014)

DD Fayetteville Solar NC, LLC – SP-2302, SUB 0; E-2, SUB 1054; Order Transfering Certificate of Public Convenience and Necessity *(Duke Energy Progress, Inc.)* (12/16/2014)

Elizabeth City Solar, LLC -- SP-3412, SUB 0; SP-4305, SUB 0; Order Transfering Certificate of Public Convenience and Necessity *(Colonial Eagle Solar, LLC)* (09/25/2014)

Everetts Solar, LLC -- SP-3441, SUB 0; SP-4512, SUB 0; Order Transfering Certificate of Public Convenience and Necessity *(Everetts Wildcat Solar, LLC)* (10/24/2014)

Graham Solar Center, LLC -- SP-2309, SUB 0; SP-4795, SUB 0; Order Transfering Certificate of Public Conven. and Necessity and Registrat. *(SunE Graham Lessee, LLC)* (12/04/2014)

Lumbee Enterprise Development, Inc. – SP-4667, SUB 0; SP-2657, SUB 0; SP-2657, SUB 1; Order Transfering Certificate of Public Convenience and Necessity and Registration Statement *(Railroad Solar Farm, LLC)* (11/04/2014)

Nan Solar Center, LLC -- SP-3131, SUB 0; E-2, SUB 1056; Order Transfering Certificate of Public Convenience and Necessity *(Duke Energy Progress, Inc.)* (12/16/2014)

SMALL POWER PRODUCERS – Sale/Transfer *(Continued)*

SolarGreen Eco-Industrial Solar Park 1, LLC -- SP-3545, SUB 0; SP-884, SUB 6; Order Transfering Certificate of Public Convenience and Necessity *(SolarGreen Development, LLC)* (12/05/2014)

SunEnergy 1, LLC -- SP-751,

SUB 6; SP-3303, SUB 0; Order Amending and Transfering Certificate of Public Convenience and Necessity *(SunEnergy 1-Scotland Neck, LLC)* (01/22/2014)

SUB 9; SP-3777, SUB 0; Order Transfering Certificate of Public Convenience and Necessity *(Albertson Solar, LLC)* (06/16/2014)

SUB 11; SP-3775, SUB 0; Order Transfering Certificate of Public Convenience and Necessity *(Choco Solar, LLC)* (06/16/2014)

SUB 18; SP-4491, SUB 0; Order Transfering Certificate of Public Convenience and Necessity *(Creswell Alligood Solar, LLC)* (10/10/2014)

SunPower Corporation Systems -- SP-2083, SUB 0; SP-1642, SUB 4; Order Transfering Certificate of Public Convenience and Necessity *(Apple, Inc.)* (07/23/2014)

Warsaw Farm, LLC -- SP-2526, SUB 0; E-2, SUB 1055; Order Transfering Certificate of Public Convenience and Necessity *(Duke Energy Progress, Inc.)* (12/16/2014)

SPECIAL CERTIFICATE/PAYPHONES

SPECIAL CERTIFICATE/PAYPHONES – Cancellation of Certificate

Alamance Rescue Mission; Piedmont Rescue Mission, Inc., d/b/a -- SC-1396, SUB 1; Order Canceling Certificate (11/13/2014)

Caltel, Inc. of North Carolina -- SC-1170, SUB 4; Order Canceling Certificate (08/25/2014)

EagleTel, Inc. -- SC-1768, SUB 1; Order Canceling Certificate (10/29/2014)

FSH Communications, LLC -- SC-1798, SUB 1; Order Canceling Certificate (04/24/2014)

Intellicom; Allen Lamont Scott, d/b/a -- SC-1689, SUB 2; Order Canceling Certificate (07/23/2014)

SPECIAL CERTIFICATE/PAYPHONES – Certificate

Crown Correctional Telephone, Inc. -- SC-1818, SUB 0; Order Granting PSP Certificate (01/23/2014)

SPECIAL CERTIFICATE/PAYPHONES – Name Change

CenturyLink Public Communications, Inc. -- SC-1474, SUB 6; Order Reissuing Special Certificate Due to Name and Address Change (04/03/2014)

Public Communications Services, Inc. -- SC-1802, SUB 1; Order Reissuing Certificate Due to Name Change (10/28/2014)

Value-Added Communications, Inc. -- SC-804, SUB 6; Order Reissuing Certificate Due to Name Change (10/28/2014)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS

TELECOMMUNICATIONS – Cancellation of Certificate

AMI Communications, Inc. – P-409, SUB 1; Order Canceling Certificate (11/25/2014)
Capital Communications Consultants, Inc. -- P-1518, SUB 2; Order Canceling Certificates (07/24/2014)
CenturyTel Long Distance, LLC -- P-1361, SUB 1; Order Canceling Certificate (09/10/2014)
Cheap2Dial Telephone, LLC -- P-1435, SUB 1; Order Canceling Certificate (04/03/2014)
Embarq Communications, Inc. -- P-1377, SUB 4; Order Canceling Certificates (09/10/2014)
Entrix Telecom, Inc. -- P-1239, SUB 1; Order Cancelling Certificate (01/15/2014)
Infotelecom, LLC -- P-1375, SUB 3; Order Canceling Certificates (01/15/2014)
Legent Communications Corp. -- P-1150, SUB 2; Order Canceling Certificate (06/19/2014)
Madison River Communications, LLC -- P-736, SUB 7; Order Canceling Certificates (09/10/2014)
STi Prepaid, LLC -- P-1433, SUB 1; Order Canceling Certificate (04/11/2014)
Teleconnect Long Distance Services and Systems Co. -- P-1382, SUB 1; Order Canceling Certificate (11/25/2014)
Telescan, Inc. -- P-878, SUB 1; Order Canceling Certificate (03/17/2014)
Verizon Enterprise Solutions, LLC -- P-574, SUB 2; Order Canceling Certificate (11/25/2014)
Voicenet Telephone, LLC -- P-1321, SUB 1; Order Canceling Certificate (02/18/2014)
@Communications, Inc. -- P-742, SUB 3; Order Cancelling Certificates and Closing Dockets (02/07/2014)

TELECOMMUNICATIONS -- Certificate

LOCAL CERTIFICATE

Orders Issued

Company	Docket No.	Date
Campus Communications Group, Inc.	P-1192, SUB 2	(05/09/2014)
ETC Communications, LLC	P-1566, SUB 0	(05/07/2014)
Onvoy, LLC	P-1562, SUB 1	(01/08/2014)
Talk America Services, LLC	P-1570, SUB 1	(10/29/2014)
ThinQ, Inc.	P-1571, SUB 0	(10/03/2014)
Tri-County Communications, Inc.	P-1001, SUB 1	(01/21/2014)
Vodafone US, Inc.	P-1563, SUB 1	(06/20/2014)
Wide Voice, LLC	P-1567, SUB 1	(05/29/2014)

ORDERS AND DECISIONS LISTED

LONG DISTANCE CERTIFICATE
Orders Issued

Company	Docket No.	Date
AllvoiTel, Inc.	P-1569, SUB 0	(07/25/2014)
City Communications, Inc.	P-1568, SUB 0	(05/27/2014)
ETC Communications, LLC	P-1566, SUB 1	(05/14/2014)
South American Telecom, Inc.	P-1572, SUB 0	(11/24/2014)
Talk America Services, LLC	P-1570, SUB 0	(10/27/2014)
Toly Digital Networks, Inc.	P-1564, SUB 0	(01/27/2014)
Wide Voice, LLC	P-1567, SUB 0	(05/14/2014)

TELECOMMUNICATIONS – Complaint

BellSouth Telecommunications, LLC -- P-55, SUB 1894; Order Dismissing Complaint and Closing Docket *(Darryl Evanstein Montague)* (01/02/2014)

TELECOMMUNICATIONS -- Contracts/Agreements

ORDER APPROVING AGREEMENT(s) *or* ORDER APPROVING AMENDMENT(s)
Orders Issued

Barnardsville Telephone Company -- P-75,
SUB 75; P-76, SUB 64; P-60, SUB 83 *(Saluda Mountain Telephone Co., Service Telephone Co. & Sprint Spectrum L.P.)* (10/14/2014)

BellSouth Telecommunications, LLC – P-55,
SUB 1430 *(Metropolitan Telecommunications of North Carolina, Inc.)* (12/17/2014)
SUB 1487 *(Windstream Norlight, Inc.)* (04/15/2014)
SUB 1590 *(New Cingular Wireless PCS, LLC)* (06/16/2014)
SUB 1633 *(IDT America, Corp.)* (12/17/2014)
SUB 1676 *(EarthLink Business, LLC)* (07/23/2014)
SUB 1677 *(TNCI Operating Company, LLC)* (08/27/2014); (12/17/2014)
SUB 1713 *(Windstream KDL, Inc.)* (04/15/2014)
SUB 1721 *(MegaPath Corporation)* (02/20/2014)
SUB 1772 *(Peerless Network of North Carolina, LLC)* (10/14/2014)
SUB 1779 *(Alternative Phone, Inc.)* (05/13/2014)
SUB 1792 *(Cincinnati Bell Any Distance, Inc.)* (11/26/2014)
SUB 1826 *(Granite Telecommunications, LLC)* (11/26/2014)
SUB 1853 *(Rosebud Telephone, LLC)* (11/26/2014)
SUB 1860 *(DukeNet Communications, LLC)* (07/23/2014)
SUB 1878 *(New Horizons Communications Corp.)* (12/17/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued *(Continued)*

BellSouth Telecommunications, LLC – P-55, *(Continued)*
SUB 1883 *(365 Wireless, LLC)* (02/20/2014)
SUB 1889 *(CeBridge Telecom NC, LLC)* (02/20/2014); (07/23/2014)
SUB 1895 *(Zayo Group, LLC)* (01/15/2014)
SUB 1897 *Crosstel Tandem, Inc.)* (04/15/2014)
SUB 1898 *(Carrboro Telephone, Inc.)* (04/15/2014)
SUB 1900 *(Image Access, Inc.)* (07/23/2014)
SUB 1901 *(Onvoy, LLC)* (11/26/2014)
Carolina Telephone and Telegraph Co./Central Telephone Co. -- P-7,
SUB 1034; P-10, SUB 669 *(Sprint Spectrum, L.P.)* (06/16/2014)
SUB 1263; P-10, SUB 878 *(EarthLink Business, LLC)* (08/27/2014)
SUB 1264; P-10, SUB 879 (*NHC Communications)* (11/26/2014)
CenturyLink, d/b/a; Mebtel, Inc. -- P-35,
SUB 127 *(Teleport Communications of America, LLC)* (03/20/2014)
SUB 128 *(MetTel, d/b/a)* (04/15/2014)
SUB 129 *(NHC Communications)* (11/26/2014)
Citizens Telephone Company -- P-12, SUB 114; P-779, SUB 15 *(Level 3 Communications, LLC)* (08/27/2014)
EarthLink Business, d/b/a; DeltaCom, LLC -- P-500, SUB 18; P-500, SUB 18A *(BellSouth Telecommunications, LLC)* (04/15/2014)
Frontier Communications of the Carolinas, Inc. -- P-1488,
SUB 11 *(Time Warner Cable, d/b/a)* (01/15/2014)
SUB 34 *(365 Wireless, LLC)* (01/15/2014)
SUB 38 *(Morris Communications, Inc.)* (10/14/2014)
SUB 39 *(ETC Communications, L.L.C.)* (10/14/2014)
Windstream Concord Telephone, Inc. -- P-16,
SUB 240; P-31, SUB 164; P-118, SUB 170 *(Windstream Lexcom Comm., Inc., Windstream North Carolina, LLC & Teleport Comm. of America, LLC)* (10/14/2014)
SUB 254 *(Intelacloud, d/b/a)* (01/15/2014)
SUB 255 *(AT&T Mobility, d/b/a)* (03/20/2014)
SUB 256 *(Spirit Telecom, d/b/a)* (05/13/2014)
SUB 259; P-31, SUB 165; P-118, SUB 194 *(Windstream Lexcom Communications., Inc., Windstream North Carolina, LLC & CenturyLink Communications, LLC)* (12/17/2014)
SUB 239; P-31, SUB 163; P-118, SUB 169 *(Windstream Lexcom Comm., Inc., Windstream North Carolina, LLC, & AT&T Corp.)* (10/14/2014)
Windstream Lexcom Communications, Inc. -- P-31,
SUB 156 *(tw telecom of north carolina l.p.)* (01/15/2014)
SUB 157 *(Intelecloud)* (01/15/2014)
SUB 158 *(AT&T Mobility)* (03/20/2014)
SUB 162 *(Access/On Interexchange Services, Inc.)* (10/14/2014)

ORDER APPROVING AGREEMENT(s) ***or***
ORDER APPROVING AMENDMENT(s)
Orders Issued *(Continued)*

Windstream North Carolina, LLC -- P-118,
SUB 188 *(Intelacloud, d/b/a)* (01/15/2014)
SUB 189 *(AT&T Mobility, d/b/a)* (03/20/2014)
SUB 191 *(Sprint Telecom, d/b/a)* (05/13/2014)

TELECOMMUNICATIONS -- Miscellaneous

AT&T North Carolina, d/b/a; BellSouth Telecommunications, LLC -- P-55, SUB 1896; Order Granting Petition to Discontinue Offering Feature Group C Access Service (02/20/2014)
Frontier Communications of the Carolinas LLC -- P-1488, SUB 37; Order Granting Numbering Resources (06/20/2014)
Teleport Communications America, LLC -- P-1547, SUB 2; Order Granting Numbering Resources (05/30/2014)
Verizon Access Transmission Services -- P-474, SUB 22; Order Granting Numbering Resources (09/22/2014)
Windstream Lexcom Communications, Inc. -- P-31, SUB 161; Order Granting Numbering Resources (08/20/2014)
Windstream North Carolina, LLC -- P-118, SUB 190; Order Granting Numbering Resources (02/05/2014)

TELECOMMUNICATIONS – Sale/Transfer

MegaPath Corporation -- P-775, SUB 9; P-1527, SUB 2; Order Permitting Discontinuance of Service *(GC Pivotal, LLC)* (12/04/2014)

TRANSPORTATION

TRANSPORTATION – Cancellation of Certificate

Blue Ridge Movers, Inc. -- T-4359, SUB 5; Order Canceling Certificate (07/10/2014)
Carolina Classic Transport, LLC -- T-4212, SUB 6; Order Cancelling Certificate (10/20/2014)
Holloway Moving & Storage, Inc. -- T-4122, SUB 6; Order Canceling Certificate of Exemption (03/26/2014)
Moore and Moore Movers, LLC -- T-4522, SUB 1; Order Canceling Certificate of Exemption (03/26/2014)

ORDERS AND DECISIONS LISTED

TRANSPORTATION -- Certificate

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION

Orders Issued

Company	Docket No.	Date
Affordable Movers and Packers	T-4554, SUB 0	(10/06/2014)
Anderson Moving Co.	T-4320, SUB 0	(11/06/2014)
Austin's Moving Company, LLC	T-4550, SUB 0	(12/04/2014)
C & L Movers	T-4543, SUB 0	(09/11/2014)
Carey Moving & Storage of Charlotte, Inc.	T-4521, SUB 0	(02/11/2014)
Carolina Moving Solutions	T-4529, SUB 0	(03/14/2014)
Dakydes Moving & Delivery, LLC	T-4557, SUB 0	(12/29/2014)
Daniel's Moving & Storage, LLC	T-4527, SUB 0	(01/10/2014)
Deb & Company Movers	T-4531, SUB 0	(05/16/2014)
Family Movers Express	T-4525, SUB 0	(03/10/2014)
L & J Moving and Storage Raleigh	T-4547, SUB 0	(09/03/2014)
Lightspeed Moving Company, LLC	T-4548, SUB 0	(09/10/2014)
Make A Move	T-4540, SUB 0	(08/06/2014)
Me and My Team	T-4544, SUB 0	(09/11/2014)
Movemart Relocation, Inc.	T-4248, SUB 4	(09/24/2014)
Road Haugs, Inc.	T-4539, SUB 0	(06/17/2014)
Smart Move USA, LLC	T-4517, SUB 0	(07/14/2014)
Superior Moving Systems, Inc.	T-4146, SUB 5	(01/24/2014)
Two Men and A Truck (Virginia Beach)	T-4546, SUB 0	(08/14/2014)
Two Men and A Truck of Mooresville	T-4533, SUB 0	(04/03/2014)
Universal Relocations, Inc.	T-4515, SUB 0	(01/31/2014)
You Move Me	T-4542, SUB 0	(07/23/2014)

Miracle Movers, d/b/a; Samantha L. Piner -- T-4510, SUB 0; Recommended Order Granting Application for Certificate of Exemption (01/08/2014); Order Denying Exceptions and Affirming Recommended Order (02/04/2014)

TRANSPORTATION – Name Change

Ahlgren's Transport, LLC -- T-4481, SUB 3; Order Approving Name Change (12/03/2014)

American Van Lines, Inc. -- T-4396, SUB 6; Order Approving Name Change (05/30/2014)

Crabtree Family Moving, LLC -- T-4476, SUB 1; Order Approving Name Change (06/26/2014)

Family Movers Express, d/b/a -- T-4525, SUB 1; Order Approving Name Change (04/16/2014)

J.E. Ladd & Son Transfer, LLC -- T-4530, SUB 0; T-867, SUB 6; Order Approving Transfer and Name Change (04/17/2014)

J. E. Thomas & Sons Moving, LLC -- T-4311, SUB 5; Order Approving Name Change (04/30/2014)

MBM Moving Systems -- T-4396, SUB 5; Order Approving Name Change (02/10/2014)

ORDERS AND DECISIONS LISTED

TRANSPORTATION – Rate Schedules/Riders/Service Rules & Regulations

Rates-Truck -- T-825, SUB 349; Order Approving Fuel Surcharge (03/04/2014); (06/30/2014); (08/04/2014); (09/02/2014); (10/06/2014); (11/03/2014); (12/01/2014)

TRANSPORTATION – Sale/Transfer

Ballantyne & Beyond Moving, d/b/a; Stephanie Y. Johnson – T-4400, SUB 7; T-4541, SUB 0; Order Granting Request to Withdraw Application (08/21/2014)

Salisbury Moving and Storage -- T-4545, SUB 0; T-2028, SUB 11; Order Approving Transfer (10/07/2014)

TRANSPORTATION – Show Cause

Grab-N-Go Movers, LLC -- T-4477, SUB 2; Recommended Order Canceling Certificate of Exemption (08/14/2014)

Guardian Transfer & Storage, LLC -- T-4504, SUB 1; Recommended Order Canceling Certificate of Exemption (07/24/2014)

TRANSPORTATION -- Suspension

ASE Moving Services -- T-3245, SUB 10; Order Granting Authorized Suspension (07/07/2014)

Bones Taylor Moving, LLC -- T-4518, SUB 1; Order Suspending Certificate of Exemption and to Show Cause in the Matter of Revocation of Certificate of Exemption for Failure to Maintain Insurance (05/06/2014); Order Granting Authorized Suspension (06/12/2014)

Fleming-Shaw Transfer and Storage, Inc. -- T-60, SUB 4; Order Granting Authorized Suspension (03/26/2014)

Gene Ferguson Moving Co. Inc. -- T-4243, SUB 2; Order Granting Authorized Suspension (01/09/2014); Order Rescinding Order Granting Authorized Suspension (03/27/2014)

Murphy Movers, Inc. -- T-4351, SUB 3; Order Granting Authorized Suspension (01/09/2014)

West Moving and Storage Company, LLC -- T-4493,
SUB 1; Order Rescinding Order Granting Authorized Suspension (08/13/2014)
SUB 3; Order Granting Authorized Suspension (10/06/2014)

WATER AND SEWER

WATER AND SEWER – Bonding

Aqua North Carolina, Inc. -- W-218, SUB 383; Order Approving Corporate Surety Bond and Releasing Bond (03/17/2014)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 338; Order Approving Bond and Surety (04/14/2014)

Old North State Water Company, LLC -- W-1300, SUB 6; Order Approving Bond and Surety and Releasing Bond (07/21/2014)

WATER AND SEWER – Certificate

Aqua North Carolina, Inc. -- W-218,
SUB 373; Order Granting Franchise and Approving Rates (04/16/2014)
SUB 382; Recommended Order Granting Franchise and Approving Rates (08/04/2014)
SUB 394; Order Granting Franchise and Approving Rates (11/25/2014)

Dillsboro Water and Sewer, Inc. -- W-1303, SUB 0; Order Granting Franchise (08/14/2014)

Harkers Island Sewer Company, LLC -- W-1297, SUB 2; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (08/18/2014)

IA Matthews Sycamore, LLC -- W-1304, SUB 0; Order Accepting and Approving Bond, Approving Franchise and Requiring Customer Notice (08/25/2014)

Old North State Water Company, LLC -- W-1300,
SUB 0; Errata Order *(Majestic Oaks Subdiv. & Hampstead Shopping Center)* (12/01/2014)
SUB 2; Order Granting Certificate of Public Convenience and Necessity and Requiring Customer Notice *(Carolina Plantations Subdivision)* (02/17/2014)
SUB 4; Order Granting Franchise and Approving Rates *(Leone Landing Subdivision)* (07/21/2014)
SUB 5; Order Granting Franchise and Approving Rates *(Cedar Point Development)* (12/18/2014)
SUB 7; Order Granting Franchise and Approving Rates *(Blaney Farms & Yates Mill Estates Subdivisions)* (12/18/2014)
SUB 8; Order Granting Franchise and Approving Rates *(Plantation Creek Apts.)* (12/18/2014)

WATER AND SEWER – Complaint

Total Environmental Solutions, Inc. -- W-1146, SUB 10; Order Dismissing Complaint and Closing Docket *(Thomas Seymour)* (03/21/2014)

WATER AND SEWER – Contract/Agreements

Aqua North Carolina, Inc. -- W-218,
SUB 351; W-274, SUB 604; Order Recognizing Contiguous Extension and Approving Rates (04/16/2014)
SUB 357; Errata Order (03/12/2014)
SUB 361; Order Recognizing Contiguous Extension and Approving Rates (02/19/2014)
SUB 369; Order Recognizing Contiguous Extension and Approving Rates (05/19/2014)
SUB 370; Order Recognizing Contiguous Extension and Approving Rates (02/19/2014)
SUB 371; Order Recognizing Contiguous Extension and Approving Rates (04/16/2014)
SUB 372; Order Recognizing Contiguous Extension and Approving Rates (05/19/2014)
SUB 375; Order Recognizing Contiguous Extension and Approving Rates (02/19/2014)
SUB 376; Order Recognizing Contiguous Extension and Approving Rates (02/19/2014)
SUB 377; Order Recognizing Contiguous Extension and Approving Rates (04/16/2014)
SUB 379; Order Recognizing Contiguous Extension and Approving Rates (04/16/2014)
SUB 388; Order Recognizing Contiguous Extension and Approving Rates (09/02/2014)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 334; Order Recognizing Contiguous Extension and Approving Rates (05/19/2014); Errata Order (08/04/2014)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Rate Increase

A & D Water Service, Inc. -- W-1049, SUB 18; Recommended Order Granting Adjustments In Rates and Requiring Customer Notice (08/13/2014)

Aqua North Carolina, Inc. -- W-218, SUB 363; Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice (05/02/2014); Errata Order (05/08/2014); Errata Order (05/08/2014); Errata Order (05/16/2014)

B & C Development, Inc. -- W-924, SUB 1; Order Granting Rate Increase and Requiring Customer Notice (09/22/2014)

Carolina Water Service, Inc. -- W-354, SUB 336; Order Approving Refund Plan and Allowing Recovery of Undercollection (08/25/2014)

Clarke Utilities, Inc. -- W-1205, SUB 6; Order Granting Franchise, Approving Rates, and Approving Bond (07/08/2014)

Cross-State Development Corporation -- W-408, SUB 9; Order Appointing Emergency Operator and Approving Increased Rates (10/01/2014)

Etowah Sewer Company -- W-933, SUB 9; Order Granting Partial Rate Increase and Requiring Customer Notice (07/21/2014)

Farm Water Works -- W-844, SUB 6; Recommended Order Granting Increase In Rates and Requiring Customer Notice (08/12/2014)

JL Golf Management, LLC -- W-1296, SUB 1; Recommended Order Granting Rate Increase and Requiring Customer Notice (08/04/2014)

Saxapahaw Utility Company -- W-1250, SUB 4; Order Granting Rate Increase and Requiring Customer Notice (01/27/2014); Errata Order (02/07/2014)

WATER AND SEWER – Sale/Transfer

A & D Water Service, Inc. -- W-1049, SUB 17; Order Approving Transfer to Owner Exempt from Regulation, Canceling Franchise, Releasing Bond, and Requiring Customer Notice (04/01/2014)

Aqua North Carolina, Inc. -- W-218,

SUB 385; W-472, SUB 17; M-100, SUB 138; Order Approving Transfer, Granting Franchises, Approving Rates, and Requiring Refunds and Customer Notice (09/24/2014)

SUB 387; W-975, SUB 3; Order Approving Transfer, Granting Franchise, Approving Rates, and Requiring Refunds and Customer Notice (11/25/2014); Errata Order (12/12/2014)

WATER AND SEWER – Sale/Transfer *(Continued)*

Carolina Water Service, Inc., of North Carolina -- W-354,
SUB 331; Order Closing Docket (03/06/2014)
SUB 333; W-1301, SUB 0; Order Closing Dockets (01/03/2014)
SUB 341; Order Approving Transfer to Owner Exempt from Regulation, Canceling Franchise, and Requiring Customer Notice (07/08/2014)

Paragon Utilities, Inc. -- W-1139, SUB 5; W-1292, SUB 0; Order Granting Motion to Withdraw Transfer Application and Closing Dockets (10/30/2014)

Water Qualities, Inc. -- W-1264, SUB 3; W-1099, SUB 15; Order Approving Transfer of Franchise, Accepting Bond, Approving Rates, and Requiring Customer Notice (02/05/2014); Errata Order (02/06/2014); Errata Order (02/07/2014)

WATER AND SEWER – Tariff Revision for Pass-Through

Aqua North Carolina, Inc. -- W-218,
SUB 389; Order Approving Tariff Revision *(Crestwood, Lancer, Acres, and Beard Acres Subdivisions)* (07/29/2014)
SUB 390; Order Approving Tariff Revision *(Thirty-Five Subdivision)* (07/29/2014)
SUB 391; Order Approving Tariff Revision and Requiring Customer Notice *(Hawthorne at the Greene Apts. & Beaver Farms Subdiv.)* (09/03/2014)
SUB 392; Order Approving Tariff Revision and Requiring Customer Notice *(18 Subdivisions in Cumberland Co.)* (09/25/2014)
SUB 393; Order Approving Tariff Revision and Requiring Customer Notice *(Woodland Run Subdivision)* (09/25/2014)

Asheville Property Management, Inc. -- W-1145, SUB 18; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refunds (08/25/2014)

Chatham Utilities, Inc. -- W-1240, SUB 10; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (08/20/2014)

Christmount Christian Assembly, Inc. -- W-1079, SUB 13; Order Approving Tariff Revision (08/19/2014)

JACTAW Properties, LLC -- W-1209, SUB 8; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refunds (08/25/2014)

Mayfaire 1, LLC -- W-1249, SUB 7; Order Approving Tariff Revision (09/15/2014)

MECO Utilities, Inc. -- W-1166, SUB 12; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (08/20/2014)

South Asheville Water Works -- W-1104,
SUB 3; Order Approving Tariff Revision (02/19/2014); Errata Order (02/21/2014)
SUB 4; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (07/30/2014)

Town and Country Mobile Home Park -- W-1193, SUB 8; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (09/03/2014)

Watercrest Estate -- W-1021, SUB 10; M-100, SUB 138; Order Approving Tariff Revision and Requiring Refund (07/22/2014)

WATER AND SEWER – Water Contiguous Extension

Aqua North Carolina, Inc. -- W-218,
SUB 366; Order Recognizing Contiguous Extension (10/02/2014)
SUB 367; Order Recognizing Contiguous Extension (10/02/2014)
SUB 368; Order Recognizing Contiguous Extension (10/02/2014)
SUB 386; Order Recognizing Contiguous Extension (11/25/2014)

Clarke Utilities, Inc. -- W-1205, SUB 7; Order Recognizing Contiguous Extension (07/08/2014)

Rock Creek Environmental Company, Inc. -- W-830, SUB 4; Order Recognizing Contiguous Extension (04/22/2014)

WATER RESELLERS

WATER RESELLERS – Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF AUTHORITY

Orders Issued

Company	Docket No.	Date
BES Ansley Fund IX, LLC, et al. *(Ansley Falls Apartments)*	WR-1132, SUB 2	(04/25/2014)
Bluff Ridge Associates Limited Partnership *(Arbor Trace Apartments)*	WR-645, SUB 2	(01/02/2014)
Charlotte Apartment Investment, LLC *(Reserve at Hollow Creek Apartments)*	WR-969, SUB 3	(05/13/2014)
CP Lakeside, LLC *(Lakeside Apartments)*	WR-847, SUB 3	(12/15/2014)
CP Plum Creek, LLC *(Elements on Park Apartments)*	WR-1397, SUB 1	(12/15/2014)
Fairfield Olde Raleigh, LLC *(Olde Raleigh Apartments)*	WR-552, SUB 8	(01/13/2014)
Fairfield Radbourne Lake, LLC *(The Apartments at Radbourne Lake)*	WR-743, SUB 7	(12/15/2014)
Forest at Asheville Properties, LLC; The *(Bell Forest at Biltmore Park Apts.)*	WR-20, SUB 10	(12/16/2014)
Forest Durham Apts., LLC, et al. *(The Forest Apartments)*	WR-616, SUB 6	(01/27/2014)
G&I VI Courtney, LP *(Courtney Place Apartments)*	WR-775, SUB 9	(02/10/2014)
G&I VI Trinity Park, LP *(Trinity Park Apartments)*	WR-773, SUB 9	(02/03/2014)

ORDER CANCELING CERTIFICATE OF AUTHORITY
Orders Issued *(Continued)*

Company	Docket No.	Date
Holly Hill Properties, LLC		
(Holly Hill Apartments)	WR-192, SUB 8	(02/24/2014)
Lenoxplace Apartments, LLC		
(Lenox at Garners Station Apts.)	WR-1305, SUB 3	(10/27/2014)
Lofts at Weston SPE, LLC		
(The Lofts at Weston Lakeside Apts.)	WR-1445, SUB 1	(01/22/2014)
Long Creek Club Apartments, LLC		
(Long Creek Apartments)	WR-866, SUB 6	(01/06/2014)
Longview at Northlake, LLC		
(Longview Apartments)	WR-1170, SUB 3	(03/11/2014)
MP Clarion Crossing, LLC		
(Clarion Crossing Apartments)	WR-1078, SUB 4	(05/13/2014)
MPI Brittany, LLC		
(Hampton Commons Apartments)	WR-947, SUB 1	(10/21/2014)
Ocean Lynn Lake, LLC		
(The Atlantic – Lynn Lake Apts.)	WR-1265, SUB 1	(11/24/2014)
Ocean Millbrook, LLC		
(The Atlantic Millbrook Apartments)	WR-1266, SUB 1	(11/24/2014)
PAMI Grand Oaks, LLC		
(Grand Oaks Apartments)	WR-1347, SUB 2	(07/28/2014)
Simpson Financing Limited Partnership		
(The Arboretum Apartments)	WR-276, SUB 3	(08/01/2014)
Strickland Farms Apartments, LLC		
(Strickland Farms Apartments)	WR-1304, SUB 4	(12/01/2014)
TPADRP, LLC		
(Sterling Town Center Apts.)	WR-1411, SUB 2	(11/03/2014)
Tradition at Stonewater I, LP		
(The Tradition at Stonewater Apts., Ph. I)	WR-931, SUB 5	(12/17/2014)
Treetop Associates Limited Partnership		
(Treetop Apartments)	WR-1231, SUB 3	(05/01/2014)

Bluff Ridge Associates Limited Partnership -- WR-645, SUB 2; Errata Order *(Bluff Ridge Apartments)* (04/01/2014)

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Certificate

ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
ACG Southside, LLC		
(Southside Mobile Home Park)	WR-1680, SUB 0	(10/27/2014)
Addington Ridge, LLC		
(Addington Ridge Apartments)	WR-1656, SUB 0	(09/04/2014)
AERC Alpha Mill, LLC		
(Alpha Mill (Phase 2) Apartments)	WR-1649, SUB 1	(08/29/2014)
AERC Lofts at Weston, LLC		
(Lofts at Weston Apartments)	WR-1586, SUB 0	(04/21/2014)
AERC St. Mary's Square, LLC		
(St Mary's Square Apartments)	WR-1587, SUB 0	(04/21/2014)
AH Durham Apartments, LLC		
(Whetstone Apartments)	WR-1688, SUB 0	(11/12/2014)
Allen's MHP, LLC		
(Dogwood Hills Mobile Home Park)	WR-1575, SUB 0	(03/26/2014)
Amberwood Fund IV, LLC, et al.		
(Amberwood Apartments)	WR-1574, SUB 0	(03/26/2014)
Amelia Station, LLC		
(Amelia Station Apartments)	WR-1632, SUB 0	(08/14/2014)
Ansley Falls Apartments, LLC		
(Ansley Falls Apartments)	WR-1603, SUB 0	(06/02/2014)
AR I Borrower, LLC		
(Ashton Reserve at Northlake Apts.)	WR-1585, SUB 0	(04/14/2014)
Arboretum Apartments Charlotte, LLC		
(The Arboretum Apartments)	WR-1651, SUB 0	(09/03/2014)
Arwen Vista Property Owners, LLC		
(Arwen Vista Apartments)	WR-1562, SUB 0	(03/04/2014)
Asheville Holdings #1, LLC		
(Kenilworth Historic Inn Apts.)	WR-1682, SUB 0	(10/29/2014)
Ashford Place Apartments, LLC		
(Ashford Place Apartments)	WR-1707, SUB 0 WR-555, SUB 10 WR-990, SUB 6	(12/02/2014)
Ashley Park, LLC		
(Solis Sharon Square Apartments)	WR-1576, SUB 0	(07/01/2014)
Autumn Crest Apartments, LLC		
(Autumn Crest Apartments)	WR-1644, SUB 0	(08/20/2014)
BH – Marquee Station A2, LLC		
(The Village at Marquee Sta. Apts., Ph. 2)	WR-1555, SUB 0	(02/17/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
BHC – Pine Winds, LLC		
(Pine Winds Apartments, Phase I)	WR-1242, SUB 2	(06/05/2014)
Bradford I SPE, LLC		
(Bradford Luxury Apts. and Townhomes)	WR-1579, SUB 0	(03/31/2014)
Breckenridge Group Charlotte North Carolina, LLC		
(Aspen Charlotte Apartments)	WR-1684, SUB 0	(10/29/2014)
Brookstown Winston-Salem Apartments		
(Link Apartments Brookstown)	WR-1618, SUB 0	(07/16/2014)
Bryant Park Apartments, LLC		
(Morehead West Apartments)	WR-1687, SUB 0	(11/10/2014)
Carrington Park CAF II, LLC		
(Carrington Park Apartments)	WR-1686, SUB 0	(11/04/2014)
CC Apartments, LLC		
(The Greens at Centennial Campus Apts.)	WR-1683, SUB 0	(10/28/2014)
CCC Gallery Lofts, LLC		
(Gallery Lofts Apartments)	WR-1708, SUB 0	(12/02/2014)
CCC The Edison, LLC		
(The Edison Apartments)	WR-1709, SUB 0	(12/02/2014)
Centennial Northlake, LLC		
(Century Northlake Apartments)	WR-1661, SUB 0 WR-1661, SUB 1	(09/11/2014)
CF FWB Elements, LLC		
(Elements on Park Apartments)	WR-1719, SUB 0	(12/15/2014)
CF FWB Lakeside, LLC		
(Lakeside Apartments)	WR-1720, SUB 0	(12/15/2014)
CF FWB Runaway Bay, LLC		
(Runaway Bay Apartments)	WR-1728, SUB 0	(12/29/2014)
Cleveland Crossing, LLC		
(Cleveland Crossing Apartments)	WR-1592, SUB 0	(04/28/2014)
Collins Crossing Terraces, LLC		
(Collins Crossing Apartment Homes)	WR-1551, SUB 0	(01/22/2014)
Conabeer Properties, LLC		
(The Lofts at South Slope Apartments)	WR-1659, SUB 0	(09/11/2014)
Corsica Forest Apartment Associates, LLC		
(Tryon Park at Rivergate Apartments)	WR-1595, SUB 0	(05/06/2014)
Courtney at South Tryon, LLC		
(The Addison at South Tryon Apts.)	WR-1590, SUB 0	(04/28/2014)
Crabtree Village Apts. Investors, LLC		
(Solis Crabtree (Phase I) Apts.)	WR-1630, SUB 0	(08/13/2014)
Crescent Cameron Venture I, LLC		
(Crescent Cameron Village Apts.)	WR-1675, SUB 0	(10/08/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
Crescent Ninth Street Venture, I, LLC		
(Crescent Ninth Street Apartments)	WR-1653, SUB 0	(09/04/2014)
Crossing at Chester Ridge, LLC		
(Crossing at Chester Ridge Apts.)	WR-1560, SUB 0	(02/24/2014)
Dickey; George Travis		
(Twin Branch Mobile Home Park)	WR-1584, SUB 0	(05/05/2014)
Dowtin; James M.		
(Tall Pines Mobile Home Park)	WR-1577, SUB 0	(03/31/2014)
Edgeline Residential, LLC		
(Edgeline Flats on Davidson Apartments)	WR-1567, SUB 0	(03/05/2014)
Epoch Highland Park Investment Partners, LLC		
(Highland Park at Northlake Apartments)	WR-1589, SUB 0	(04/28/2014)
Fairfield Courtney Place, LLC		
(Courtney Place Apartments)	WR-1598, SUB 0	(05/05/2014)
Fairfield Trinity Park, LLC		
(Trinity Park Apartments)	WR-1597, SUB 0	(05/05/2014)
FC Hidden Creek, LLC		
(North Oaks Landing Apartments)	WR-1724, SUB 0	(12/31/2014)
Flats; The		
(The Flats on 401 Apartments)	WR-1623, SUB 0	(07/22/2014)
Gateway West-FCA, LLC		
(Gateway West Uptown Flats Apts.)	WR-1561, SUB 0	(02/24/2014)
GCC-Courtyard, LLC		
(Courtyard Apartments)	WR-1566, SUB 0	(03/05/2014)
GF Property Funding Corp.		
(Garrett West Apartments)	WR-1534, SUB 0	(02/24/2014)
GGT Crescent Alexander NC Venture, LLC		
(Crescent Alexander Village Apts.)	WR-1652, SUB 0	(09/11/2014)
GGT Patterson Place NC Venture, LLC		
(REALM Patterson Place Apts.)	WR-1679, SUB 0	(10/21/2014)
Ginkgo SAC, LLC		
(Salem Crest Apartments)	WR-1691, SUB 0	(11/18/2014)
GQ Lynn Lake, LLC		
(Lynn Lake Apartments)	WR-1726, SUB 0	(12/31/2014)
GQ Millbrook, LLC		
(Millbrook Apartments)	WR-1725, SUB 0	(12/31/2014)
Granite Falls NC Limited Partnership		
(Granite Falls Apartments)	WR-1572, SUB 0	(03/25/2014)
Greybul Woods Edge, LLC		
(Woods Edge Apartments)	WR-1581, SUB 0	(04/01/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES
Orders Issued (Continued)

Company	Docket No.	Date
Griffin and Sons Investments, LLC		
(Withrow Road Park, Section II)	WR-631, SUB 3	(02/10/2014)
Hawthorne-Midway Stratford, LLC, et al.		
(Hawthorne on the Parkway Apartments)	WR-1553, SUB 0	(02/05/2014)
Hawthorne-Midway Wilmington, LLC		
(Hawthorne at the Station Apartments)	WR-1622, SUB 0	(07/23/2014)
Heritage Circle Apartments, LLC		
(Heritage Circle Apartments)	WR-1625, SUB 0	(07/22/2014)
HWY 68 APTS, LLC		
(Signature Northpoint Apts.)	WR-1705, SUB 0	(11/25/2014)
IRT Lenoxplace Apartments Owner, LLC		
(Lenoxplace at Garners Station Apts.)	WR-1713, SUB 0	(12/09/2014)
ITAC 331, LLC		
(Forest Pointe 2 Apartments)	WR-1645, SUB 0	(08/27/2014)
Jones; Joe T. and JoAnne		
(Asbury Acres Mobile Home Park)	WR-1677, SUB 0	(10/21/2014)
K Partnership, LLC		
(Hampton Downs Apartments)	WR-1631, SUB 0	(08/14/2014)
Kenton Place Partners, LLC		
(The Reserve at Kenton Place Apts.)	WR-1609, SUB 0	(06/09/2014)
Ledges Apartments, LLC; The		
(The Ledges Apartments)	WR-1678, SUB 0	(10/21/2014)
Lofts at Little Creek, LLC; The		
(The Lofts at Little Creek Apartments)	WR-1626, SUB 0	(07/30/2014)
Loray Mill Redevelopment, LLC		
(Loray Mill Lofts Apartments)	WR-1615, SUB 0	(06/25/2014)
Madison Apartments, LLC; The		
(The Madison Apartments)	WR-1703, SUB 0	(11/25/2014)
Mellow Field Partners, LLC		
(The Avenues Apartments)	WR-1564, SUB 0	(03/04/2014)
Meridian at Harrison Pointe, LLC		
(Meridian at Harrison Point Apts.)	WR-1568, SUB 0	(03/05/2014)
Mountain High Property Management, LLC		
(Becky's Mobile Home Park)	WR-1556, SUB 0	(02/18/2014)
NHE Tract H, LLC		
(Midtown Green Apartments)	WR-1612, SUB 0	(06/16/2014)
NR Palladian Property Owner, LLC		
(The Apartments at Palladian Place)	WR-1721, SUB 0	(12/15/2014)
NXRTBH Radbourne Lake, LLC		
(The Apartments at Radbourne Lake)	WR-1722, SUB 0	(12/15/2014)

ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
Oxford City Park Apartments, LLC		
(City Park View Apartments)	WR-1647, SUB 0	(09/03/2014)
Park United, LLC		
(Country Club Apts., Phase II)	WR-1600, SUB 1	(05/12/2014)
Plantation Pointe Apartments, LLC		
(Plantation Pointe Apartments)	WR-1616, SUB 0	(07/01/2014)
Port City Investments, LLC		
(Village Green Apartments)	WR-1552, SUB 0	(01/22/2014)
Post Ballantyne, LLC		
(Post Ballantyne Apartments)	WR-1543, SUB 0	(01/06/2014)
Post Gateway Place, LLC		
(Post Gateway Place Apartments)	WR-1542, SUB 0	(11/26/2014)
PRG Clarion Crossing Associates, LLC		
(Clarion Crossing Apartments)	WR-1610, SUB 0	(06/10/2014)
PRIII/Wood Cary Parkway Apartments		
(The Bristol Apartments)	WR-1570, SUB 0	(03/25/2014)
Quadbridge HML Owner, LLC		
(Highland Mill Lofts Apartments)	WR-1613, SUB 0	(06/16/2014)
Quail Valley NC Partners, LLC		
(Quail Valley on Carmel Apartments)	WR-1674, SUB 0	(10/08/2014)
Quarters at Stones Bay II, LLC; The		
(The Quarters at Stones Bay Apts. Ph. II)	WR-1642, SUB 0	(10/20/2014)
Sagebrush Andover Woods Apartments, LLC		
(Andover Woods Apartments)	WR-1571, SUB 0	(03/25/2014)
SBV-Greensboro II, LLC		
(LeMans at Lawndale Apartments)	WR-1690, SUB 0	(11/18/2014)
Schrader Family Limited Partnership		
(Woodridge Apartments)	WR-980, SUB 10	(02/12/2014)
Six Forks Apartments, LLC		
(Bainbridge Six Forks Apartments)	WR-1596, SUB 0	(05/06/2014)
Somerstone, LLC		
(Somerstone Apartments)	WR-1557, SUB 0	(02/18/2014)
SouthPark 2 Owner, LLC		
(Mezzo1 Apartments)	WR-1669, SUB 0	(09/24/2014)
Southwood Realty Company		
(Azalea Apartments)	WR-910, SUB 15	(01/22/2014)
(Catawba Apartments)	WR-910, SUB 16	(10/08/2014)
Stafford Place, LLC		
(Stafford Place Apartments)	WR-1573, SUB 0	(03/26/2014)
Sterling TC Property Owner, LLC		
(Sterling Town Center Apartments)	WR-1710, SUB 0	(12/02/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued (Continued)

Company	Docket No.	Date
Summerlyn Holdings, LLC		
(Summerlyn Cottages Apartments)	WR-1689, SUB 0	(11/12/2014)
SWHR Mooresville, LLC		
(The Grove at Morrison Plantation Apts.)	WR-1599, SUB 0	(05/12/2014)
Swift Avenue-FCA, LLC		
(300 Swift Apartments)	WR-1727, SUB 0	(12/31/2014)
Thomasville Holly Hill, LLC		
(Holly Hill Apartments)	WR-1607, SUB 0	(06/04/2014)
Tradition at Stonewater Apartments, LLC		
(Tradition at Stonewater Apartments)	WR-1723, SUB 0	(12/17/2014)
Triangle Mills Creek, LLC		
(Mills Creek Apartments)	WR-1580, SUB 0	(04/01/2014)
Triangle Real Estate of Gastonia, Inc.		
(Bluff Ridge Apartments)	WR-1125, SUB 9	(03/11/2014)
(Arborgate Apartments)	WR-1125, SUB 13	(10/28/2014)
		(12/12/2014)
(Lakemist Apartments)	WR-1125, SUB 14	(11/10/2014)
Tryon Place Apartments, LLC		
(Tryon Place Apartments)	WR-1563, SUB 0	(03/18/2014)
VCP Grand Oaks, LLC		
(Grand Oaks Apartments)	WR-1648, SUB 0	(08/29/2014)
Village at Town Center, LLC; The		
(The Village at Town Center Apts.)	WR-1617, SUB 0	(07/15/2014)
Vyne Residential, LLC		
(The Vyne Apartments)	WR-1565, SUB 10	(03/04/2014)
Waterford at the Park DE, LLC		
(Park Apartments)	WR-1654, SUB 0	(09/04/2014)
Waterstone Weddington Partners, LLC		
(Waterstone at Weddington Apts.)	WR-1583, SUB 0	(04/08/2014)
Waypoint Stone Hollow Owner, LLC		
(Stone Hollow Apartments)	WR-1611, SUB 10	(06/16/2014)
Windridge Apartments, LLC		
(Windridge Apartments)	WR-1655, SUB 0	(09/04/2014)
Worthing Meridian, LLC		
(Heights at Meridian Apartments)	WR-1627, SUB 0	(07/30/2014)
Yards at Noda, LLC		
(Yards at Noda Apartments)	WR-1640, SUB 0	(09/11/2014)
Yopp Properties/Brookway West, LLC		
(Brookway West Apartments)	WR-1402, SUB 0	(03/04/2014)
12BMM, LLC		
(Elevation Apartments)	WR-1663, SUB 0	(09/15/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING CERTIFICATE OF AUTHORITY
AND APPROVING RATES
Orders Issued *(Continued)*

Company	Docket No.	Date
401 Oberlin, LLC		
(401 Oberlin Apartments)	WR-1657, SUB 0	(09/09/2014)
401 South Mint Street Apt. Investors, LLC		
(Element Uptown Apartments)	WR-1634, SUB 0	(08/15/2014)
425 Boylan, LLC		
(Devon 425 Apartments)	WR-1704, SUB 0	(11/25/2014)
2442 Chartres, LLC		
(Bella Vista Apartments)	WR-1578, SUB 0	(03/31/2014)

Ashley Park, LLC -- WR-1576, SUB 0; Errata Order *(Solis Sharon Square Apts.)* (08/12/2014)

Fund II Meadows, LLC, et al. -- WR-846, SUB 8; Errata Order *(The Meadows Apartments, Phase II)* (01/06/2014)

Granite Falls NC Limited Partnership -- WR-1572, SUB 0; Errata Order *(Granite Falls Apartments)* (04/14/2014)

Grey Eagle MHP, LLC -- WR-1546, SUB 0; W-1254, SUB 2; Errata Order *(Grey Eagle Estates Mobile Home Park)* (08/11/2014)

Greybul Woods Edge, LP -- WR-1581, SUB 0; Errata Order *(Woods Edge Apartments)* (04/02/2014)

Sagebrush Andover Woods Apartments, LLC -- WR-1571, SUB 0; WR-693, SUB 4; Reissued Order Granting Certificate of Authority and Approving Rates *(Andover Woods Apartments)* (05/07/2014)

SWHR Mooresville, LLC -- WR-1599, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates *(The Grove at Morrison Plantation Apartments)* (05/15/2014)

Triangle Mills Creek, Inc. -- WR-1580, SUB 0; Errata Order *(Mills Creek Apartments)* (06/18/2014)

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY
AND APPROVING RATES
Orders Issued

Company	Docket No.	Date
BHC – Pine Winds, LLC		
(Pine Winds Apts., Phase II)	WR-1242, SUB 3	(06/05/2014)
BVT Group, LLC		
(Bella Vista Townhomes Apts.)	WR-1396, SUB 2	(08/08/2014)
Eighty-Six North, LLC		
(86 North Apartments)	WR-1643, SUB 0	(08/20/2014)
MP Vista Villa, LLC		
(Vista Villa Apartments)	WR-1711, SUB 0	(12/10/2014)
Park United, LLC		
(Country Club Apartments)	WR-1600, SUB 0	(05/12/2014)

ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
PEG Chapel Hill I, LLC		
(The Apartments at Midtown 501)	WR-1641, SUB 0	(08/20/2014)
Redwood Landings, LLC		
(The Landing at Center Point Apts.)	WR-1681, SUB 0	(10/28/2014)
Seaboard Associates, LLC		
(Willow Ridge Apartments)	WR-1694, SUB 0	(11/19/2014)
Solie; Mindy S.		
(Anderson Apartments)	WR-1700, SUB 0	(11/19/2014)
Treetop Raleigh, LLC		
(Tree Top Apartments)	WR-1671, SUB 0	(09/24/2014)
Trinity Properties, LLC		
(Poplar West Apartments)	WR-1696, SUB 0	(11/19/2014)
(Governor Apartments)	WR-1696, SUB 1	(11/19/2014)
(Campus Walk Apartments)	WR-1696, SUB 2	(11/19/2014)
(Georgetown Apartments)	WR-1696, SUB 3	(11/19/2014)

PRG Clarion Crossing Associates, LLC -- WR-1610, SUB 0; Reissued Order Granting HWCCWA Certificate of Authority and Approving Rates *(Clarion Crossing Apts.)* (11/03/2014)

WATER RESELLERS – Complaint

TBR Lake Boone Owner, LLC -- WR-1374, SUB 2; Order Dismissing Complaint and Closing Docket (06/16/2014); Order Canceling Hearing, Dismissing Complaint and Closing Docket *(Kristina Keeney)* (09/30/2014)

WATER RESELLERS – Sale/Transfer

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued

Company	Docket No.	Date
AERC Alpha Mill, LLC		
(Alpha Mill (Phase 1) Apartments)	WR-1649, SUB 0 WR-1238, SUB 2	(08/29/2014)
Audubon Parc Apartments, LLC		
(Audubon Parc Apartments)	WR-1662, SUB 0 WR-1193, SUB 4	(09/11/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES
<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
BIG Arbor Village NC, LLC		
(Arbor Village Apartments)	WR-1660, SUB 0 WR-1239, SUB 4	(09/11/2014)
BIG Bedford NC, LLC		
(Yorktown Club Apartments)	WR-1672, SUB 0 WR-1128, SUB 4	(10/01/2014)
BRE Cary Parkway Apartments, LLC		
(Marquis at Cary Parkway Apts.)	WR-1637, SUB 0 WR-522, SUB 8	(09/29/2014)
BRE Edwards Mill Apartments, LLC		
(Edwards Mill Apartments)	WR-1639, SUB 0 WR-503, SUB 7	(09/29/2014)
BRE Northcross Apartments, LLC		
(Marquis at Northcross Apts.)	WR-1638, SUB 0 WR-864, SUB 3	(09/29/2014)
CCC Brassfield Park, LLC		
(Brassfield Park Apartments)	WR-1619, SUB 0 WR-1038, SUB 3	(07/21/2014)
CCC One Norman Square, LLC		
(One Norman Square Apts.)	WR-1628, SUB 0 WR-1271, SUB 3	(08/08/2014)
DMARC 2007-CD5 Riese Drive, LLC		
(Marchester on Millbrook Apartments)	WR-1593, SUB 0 WR-857, SUB 2	(07/01/2014)
DPG Investments, LLC		
(Willow Creek Mobile Home Park)	WR-1673, SUB 0 WR-981, SUB 1	(10/07/2014)
G&I VIII Brier Creek, LLC		
(Crest at Brier Creek Apts.)	WR-1650, SUB 0 WR-1429, SUB 2	(09/03/2014)
Ginkgo OBC, LLC		
(Oak Park at Briar Creek Apts.)	WR-1558, SUB 0 WR-807, SUB 5	(02/18/2014)
GQ Allerton, LLC		
(Allerton Place Apartments)	WR-1608, SUB 0 WR-1280, SUB 2	(06/04/2014)
GQ Cary Brook, LLC		
(Cary Brook Apartments)	WR-1604, SUB 0 WR-1295, SUB 1	(05/27/2014)
Junction 1504, LLC		
(Junction 1504 Apartments)	WR-1559, SUB 0 WR-1376, SUB 2	(02/24/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
KBS Legacy Partners Grand, LLC		
(Legacy Grand at Concord Apts.)	WR-1594, SUB 0 WR-965, SUB 2	(05/05/2014)
Kip-Dell Homes, Inc.		
(Pine Winds Apts., Phase I)	WR-341, SUB 4 WR-1242, SUB 4	(11/25/2014)
LAT Battleground, LLC		
(Landmark Battleground Park Apts.)	WR-1550, SUB 0 WR-696, SUB 3	(01/06/2014)
Legacy at Wakefield/HF, LLC, et al.		
(Legacy at Wakefield Apartments)	WR-1667, SUB 0 WR-1098, SUB 4	(09/23/2014)
LHNH – Country Club Apartments, LLC		
(Country Club Apartments)	WR-1591, SUB 0 WR-1188, SUB 2	(04/28/2014)
LSREF3 Bravo (Charlotte), LLC		
(Crossing at Quail Hollow Apts.)	WR-1718, SUB 0 WR-764, SUB 9	(12/30/2014)
(Harris Pond Apartments)	WR-1718, SUB 3 WR-771, SUB 9	(12/17/2014)
(Mallard Creek Apartments)	WR-1718, SUB 2 WR-776, SUB 9	(12/17/2014)
(Northlake Apartments)	WR-1718, SUB 4 WR-768, SUB 9	(12/23/2014)
(Providence Court Apartments)	WR-1718, SUB 5 WR-758, SUB 9	(12/30/2014)
(Sharon Crossing Apartments)	WR-1718, SUB 1 WR-770, SUB 17	(12/16/2014)
LSREF3 Bravo (Raleigh), LLC		
(Cooper Mill Apartments)	WR-1717, SUB 4 WR-767, SUB 9	(12/16/2014)
(Crest at West End Apartments)	WR-1717, SUB 0 WR-765, SUB 6	(12/30/2014)
(Spring Forest Apartments)	WR-1717, SUB 6 WR-766, SUB 10	(12/30/2014)
(The Meadows at Kildare Apts.)	WR-1717, SUB 3 WR-769, SUB 9	(12/17/2014)
(The Reserve at Lake Lynn Apts.)	WR-1717, SUB 2 WR-761, SUB 10	(12/30/2014)
(Walnut Creek Apartments)	WR-1717, SUB 1 WR-777, SUB 10	(12/30/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
LSREF3 Bravo REO, LLC		
(Brynn Marr Village Apartments)	WR-1715, SUB 0 WR-759, SUB 6	(12/10/2014)
(Colony Village Apartments)	WR-1715, SUB 2 WR-779, SUB 6	(12/17/2014)
(Liberty Crossing Apartments)	WR-1715, SUB 1 WR-760, SUB 6	(12/10/2014)
LSREF3 Bravo (Wilmington), LLC		
(Cape Harbor Apartments)	WR-1716, SUB 0 WR-763, SUB 7	(12/16/2014)
(Clear Run Apartments)	WR-1716, SUB 4 WR-762, SUB 8	(12/16/2014)
(Crosswinds Apartments)	WR-1716, SUB 5 WR-772, SUB 8	(12/16/2014)
(Forest Hills Apartments)	WR-1716, SUB 3 WR-968, SUB 6	(12/17/2014)
(Mill Creek Apartments)	WR-1716, SUB 2 WR-774, SUB 8	(12/17/2014)
(The Creek Apartments)	WR-1716, SUB 1 WR-770, SUB 18	(12/23/2014)
Manor Six Abbey 1825, LLC		
(Manor Six Forks Luxury Apts.)	WR-1685, SUB 0 WR-1493, SUB 1	(11/04/2014)
Mebane Operating Company, LLC		
(Carden Place Apartments)	WR-1605, SUB 0 WR-1121, SUB 2	(05/27/2014)
Metro 808 Charlotte, LLC		
(Metro 808 Apartments)	WR-1714, SUB 0 WR-1123, SUB 2	(12/10/2014)
MP Beacon Glen, LLC		
(Beacon Glen Apartments)	WR-1665, SUB 0 WR-1140, SUB 5	(10/01/2014)
Paces Village, LLC		
(Paces Village Apartments)	WR-1554, SUB 0 WR-1291, SUB 3	(02/12/2014)
Pacifica Mizell, LLC		
(Brannon Park Apartments)	WR-1676, SUB 0 WR-1243, SUB 2	(10/14/2014)
Passco Brier Creek DST		
(Carrington at Brier Creek Apartments)	WR-1614, SUB 0 WR-860, SUB 3	(06/25/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

Orders Issued *(Continued)*

Company	Docket No.	Date
Passco Columns DST		
(Wakefield Apartments)	WR-1633, SUB 0 WR-1337, SUB 2	(08/08/2014)
Passco Wakefield Glen DST		
(Wakefield Glen Apartments)	WR-1582, SUB 0 WR-892, SUB 4	(04/01/2014)
Properties of Assurance, LLC		
(Bavarian Point Private Community)	WR-1668, SUB 1 WR-589, SUB 9	(09/23/2014)
(Carolina Pines Private Community)	WR-1668, SUB 0 WR-589, SUB 8	(09/23/2014)
PS Thornberry Owner, LLC		
(Thornberry Apartments)	WR-1666, SUB 0 WR-106, SUB 10	(09/17/2014)
Quarterside (K21) Apartments, LLC		
(Quarterside Apartments)	WR-1602, SUB 0 WR-1210, SUB 3	(05/19/2014)
Raleigh Multifamily Partners, LLC		
(Regency Place Apartments)	WR-1621, SUB 0 WR-714, SUB 9	(07/16/2014)
RCG Maybelle, LLC		
(Pinewood Apartments)	WR-1646, SUB 0 WR-1380, SUB 1	(08/27/2014)
Riverwalk Denver, LLC		
(Riverwalk Apartments)	WR-1658, SUB 0 WR-870, SUB 1	(09/09/2014)
South LaSalle Apartments, LLC		
(The Heights at South LaSalle Apts.)	WR-1629, SUB 0 WR-1450, SUB 1	(08/08/2014)
Timber Hollow Apartments, LLC		
(Timber Hollow Apartments)	WR-1635, SUB 0 WR-1382, SUB 1	(08/18/2014)
TS Brier Creek, LLC		
(Waterstone at Brier Creek Apts.)	WR-1620, SUB 0 WR-1438, SUB 3	(07/16/2014)
TS New Bern, LLC		
(Fountains Southend Apartments)	WR-1541, SUB 0 WR-1410, SUB 1	(05/05/2014)
Village at Broadstone Station I, LLC, et al.		
(Village at Broadstone Station Apts.)	WR-1601, SUB 0 WR-1441, SUB 1	(05/12/2014)

ORDERS AND DECISIONS LISTED

ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES

<u>*Orders Issued*</u> *(Continued)*

Company	Docket No.	Date
WBCMT 2006-C29 Cottage Place, LLC		
(Beechwood Apartments)	WR-1588, SUB 0 WR-664, SUB 3	(04/21/2014)
WE Montclaire Estates, LLC		
(Montclaire Estates Apartments)	WR-1636, SUB 0 WR-456, SUB 5	(08/19/2014)
Wilkinson High Point I, LLC		
(Fox Hollow Apartments)	WR-1670, SUB 0 WR-1187, SUB 3	(09/24/2014)
Willow Rentals, LLC		
(Willow Trail Mobile Home Park)	WR-1569, SUB 0 WR-324, SUB 1	(03/11/2014)
WMCi Raleigh VIII, LLC		
(Bexley at Park West Village Apts.)	WR-1693, SUB 0 WR-1570, SUB 1	(11/18/2014)
55 Regal Holdings, LLC		
(The Oasis at Regal Oaks Apts.)	WR-1624, SUB 0 WR-1119, SUB 6	(07/22/2014)
639 Archdale, LLC		
(The Highlands Apartments)	WR-1606, SUB 0 WR-1416, SUB 3	(06/03/2014)

CCC One Norman Square, LLC -- WR-1628, SUB 0; WR-1271, SUB 3; Errata Order *(One Norman Square Apartments)* (08/11/2014)

LAT Battleground Park, LLC -- WR-1550, SUB 0; Errata Order *(Landmark Battleground Park Apts.)* (01/15/2014)

Wilkinson High Point I, LLC -- WR-1670, SUB 0; WR-1187, SUB 3; Errata Order *(Fox Hollow Apartments)* (09/29/2014)

55 Regal Holdings, LLC -- WR-1624, SUB 0; WR-1119, SUB 1; Errata Order *(The Oasis at Regal Oaks Apts.)* (07/23/2014)

ORDER GRANTING TRANSFER OF HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

<u>*Orders Issued*</u>

Company	Docket No.	Date
Interurban Silas Creek, LLP		
(Colonial Village Apartments)	WR-1664, SUB 0 WR-1520, SUB 2	(11/27/2014)
Kip-Dell Homes, Inc.		
(Pine Winds Apts., Phase II)	WR-341, SUB 5 WR-1242, SUB 5	(11/25/2014)

ORDERS AND DECISIONS LISTED

WATER RESELLERS – Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION
Orders Issued

Company	Docket No.	Date
Abbington SPE, LLC		
(Abbington Place Apartments)	WR-596, SUB 3	(07/15/2014)
Addison Point, LLC		
(Addison Point Apartments)	WR-748, SUB 6	(12/19/2014)
Admiral Pointe, LLC		
(Admiral Pointe Apartments)	WR-1205, SUB 1	(08/06/2014)
AERC Arboretum, LP		
(The Arboretum Apartments)	WR-1277, SUB 1	(09/23/2014)
AERC Blakeney, LP		
(The Apartments at Blakeney)	WR-1547, SUB 1	(09/23/2014)
AERC Crossroads, LP		
(The Park at Crossroads Apts.)	WR-1328, SUB 1	(09/23/2014)
AERC Lofts at Weston, LLC		
(Lofts at Weston Apartments)	WR-1586, SUB 1	(10/13/2014)
AERC Southpoint, LP		
(Southpoint Village Apartments)	WR-1312, SUB 1	(09/23/2014)
AERC St. Mary's Square, LLC		
(St. Mary's Square Apartments)	WR-1587, SUB 1	(09/23/2014)
Alaris Village Apartments, LLC		
(Alaris Village Apartments)	WR-894, SUB 5	(02/04/2014)
Amberleigh Shores, LLC		
(Amberleigh Shores Apartments)	WR-1522, SUB 1	(09/08/2014)
Amberton at Stonewater, LLC		
(Amberton at Stonewater Apartments)	WR-1455, SUB 1	(02/03/2014)
(Amberton at Stonewater Apartments)	WR-1455, SUB 2	(08/28/2014)
Amelia Village Phase I, LLC		
(Amelia Village Apartments)	WR-1220, SUB 1	(03/18/2014)
AMFP I Hamilton Ridge, LLC		
(Hamilton Ridge Apartments)	WR-805, SUB 7	(07/22/2014)
AMFP II Four Seasons, LLC		
(Four Seasons at Umstead Park Apts.)	WR-1165, SUB 3	(07/16/2014)
Ansley Falls Apartments, LLC		
(Ansley Falls Apartments)	WR-1603, SUB 1	(08/08/2014)
Apartments at Crossroads, LLC; The		
(Legacy Crossroads Apts.)	WR-851, SUB 6	(09/10/2014)
AR I Borrower, LLC		
(Ashton Reserve at Northlake Apts.)	WR-1585, SUB 1	(09/15/2014)
Arwen Vista Property Owner, LLC		
(Arwen Vista Apartments)	WR-1562, SUB 1	(06/24/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued *(Continued)*

Company	Docket No.	Date
Ascot Point Village Apartments, LLC		
(Ascot Point Village Apts.)	WR-273, SUB 10	(02/03/2014)
(Ascot Point Village Apartments)	WR-273, SUB 11	(08/28/2014)
Ashborough Investors, LLC		
(Ashborough Apartments)	WR-489, SUB 7	(07/29/2014)
Asheville Apartments Investors, LLC		
(Reserve at Asheville Apts.)	WR-1327, SUB 2	(08/11/2014)
Ashford SPE, LLC		
(Ashford Place Apartments, Phase I)	WR-555, SUB 9	(08/08/2014)
Ashford SPE 2, LLC		
(Ashford Place Apartments, Phase II)	WR-990, SUB 5	(08/08/2014)
Ashley Park Associates, LLC		
(Ashley Park at Brier Creek Apts.)	WR-960, SUB 2	(11/10/2014)
Atkins Circle I, LLC		
(Atkins Circle I Apartments)	WR-277, SUB 4	(03/18/2014)
Atkins Circle II, LLC		
(Atkins Circle Phase II Apartments)	WR-747, SUB 2	(03/18/2014)
Auston Grove- Raleigh Apartments, LP		
(Auston Grove Apartments)	WR-233, SUB 13	(07/01/2014)
Auston Woods – Charlotte – Phase I Apts. L.P.		
(Auston Woods Apartments)	WR-232, SUB 5	(03/10/2014)
(Auston Woods Apartments)	WR-232, SUB 6	(08/25/2014)
Auston Woods – Charlotte – Phase II Apts. L.P.		
(Auston Woods II Apartments)	WR-721, SUB 5	(03/10/2014)
(Auston Woods II Apartments)	WR-721, SUB 6	(08/25/2014)
Autumn Park Owner, LLC		
(Autumn Park Charlotte Apts.)	WR-1378, SUB 2	(08/06/2014)
Avalon Apartments DE, LLC		
(Avalon Apartments)	WR-1348, SUB 2	(07/21/2014)
Avery Millbrook, LLC		
(Millbrook Apartments I)	WR-1020, SUB 10	(12/19/2014)
(Avery Square Apartments)	WR-1020, SUB 11	(12/19/2014)
Barrington Apartments, LLC		
(Barrington Apartments)	WR-384, SUB 12	(09/10/2014)
Battleground North Apartments, LLC		
(Battleground North Apartments)	WR-672, SUB 4	(02/03/2014)
(Battleground North Apartments)	WR-672, SUB 5	(08/29/2014)
BBR/Barrington, LLC		
(Barrington Place Apartments)	WR-619, SUB 7	(09/08/2014)
BBR/Carriage Club, LLC		
(Carriage Club Apartments)	WR-610, SUB 5	(09/08/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Beachwood Associates, LLC		
(Beachwood Park Apartments)	WR-880, SUB 3	(12/08/2014)
Bel Hickory Grove Holdings, LLC		
(Kimmerly Glen Apartments)	WR-1054, SUB 4	(09/30/2014)
Bel Pineville Holdings, LLC		
(Berkshire Place Apartments)	WR-1037, SUB 4	(09/30/2014)
Bel Ridge Holdings, LLC		
(McAlpine Ridge Apartments)	WR-1053, SUB 4	(10/07/2014)
Bell Fund IV Morrison Apts., LLC		
(Bell Morrison Apartments)	WR-1250, SUB 3	(09/11/2014)
Bell Fund IV Morrisville Apartments, LLC		
(Bell Preston View Apartments)	WR-1391, SUB 2	(09/18/2014)
Bell Fund V Wakefield, LLC		
(Bell Wakefield Apartments)	WR-1540, SUB 1	(09/23/2014)
Berrington Village Apartments, LLC		
(Berrington Village Apartments)	WR-1153, SUB 2	(02/04/2014)
(Berrington Village Apartments)	WR-1153, SUB 3	(08/28/2014)
BES Steele Creek Fund IX, LLC, et al.		
(Preserve at Steele Creek Apts.)	WR-1352, SUB 2	(08/25/2014)
Best Mulch, Inc.		
(Clairmont Crest Mobile HP)	WR-513, SUB 6	(07/25/2014)
BH – Marquee Station 1, LLC		
(The Village at Marquee Station Apts.)	WR-1459, SUB 1	(08/04/2014)
BH – Marquee Station A2, LLC		
(The Village at Marquee Station Apts., Phase 2)	WR-1555, SUB 1	(04/14/2014)
(The Village at Marquee Station Apts. Phase 2)	WR-1555, SUB 2	(08/04/2014)
BHI-SEI Mariners, LLC		
(Mariners Crossing Apartments)	WR-1228, SUB 1	(09/22/2014)
BMA Bellemeade Apartments, LLC		
(Highland Ridge Apts.)	WR-814, SUB 4	(12/15/2014)
BMA Davidson Apartments, LLC		
(Davidson Apartments)	WR-707, SUB 4	(08/01/2014)
BMA Eden Apartments, LLC		
(Arbor Glen Apartments)	WR-728, SUB 5	(02/04/2014)
BMA Heatherwood Kensington Apts., LLC		
(Heatherwood/Kensington Apartments)	WR-708, SUB 4	(08/01/2014)
BMA Huntersville Apartments, LLC		
(Huntersville Apartments)	WR-811, SUB 6	(07/24/2014)
BMA Monroe III, LLC		
(Woodbrook Apartments)	WR-812, SUB 7	(08/26/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
BMA North Sharon Amity, LLC		
(Sharon Pointe Apartments)	WR-810, SUB 6	(07/24/2014)
BMA Water's Edge Apartments, LLC		
(Water's Edge Apartments)	WR-711, SUB 4	(08/01/2014)
BMA Wexford, LLC		
(Wexford Apartments)	WR-813, SUB 6	(07/24/2014)
BNP/Abbington, LLC		
(Abbington Place Apartments)	WR-454, SUB 8	(07/29/2014)
BNP/Pepperstone, LLC		
(Pepperstone Apartments)	WR-445, SUB 9	(07/29/2014)
Brannigan Village Apartments, LLC		
(Brannigan Village Apartments)	WR-380, SUB 8	(02/03/2014)
Branson-Coleman Properties, LLC		
(Madison Heights Apartments)	WR-1503, SUB 1	(10/06/2014)
BRC Abernathy, LLC, et al.		
(Abernathy Park Apartments)	WR-1057, SUB 4	(07/21/2014)
BRC Charlotte 485, LLC		
(Halton Park Apartments)	WR-501, SUB 7	(08/08/2014)
BRC Jacksonville Commons, LLC		
(Jacksonville Commons Apartments)	WR-1275, SUB 1	(07/15/2014)
BRC Knightdale, LLC		
(Berkshire Park Apartments)	WR-938, SUB 5	(07/16/2014)
BRC Majestic Apartments, LLC		
(Palladium Park Apartments)	WR-374, SUB 5	(07/25/2014)
BRC Salisbury, LLC		
(Salisbury Village Apartments)	WR-500, SUB 4	(08/11/2014)
BRC Whites Mill, LLC		
(Alexandria Park Apartments)	WR-830, SUB 4	(07/25/2014)
BRC Wilson, LLC		
(Thornberry Park Apartments)	WR-502, SUB 4	(07/28/2014)
Brightwood Crossing Apartments, LLC		
(Brightwood Crossing Apartments)	WR-543, SUB 5	(10/01/2014)
BRNA, LLC		
(Bryn Athyn Apartments)	WR-75, SUB 14	(08/13/2014)
Broadstone Village Apartments, LLC		
(Broadstone Village Apartments)	WR-378, SUB 8	(08/29/2014)
Bromley Park, LLC		
(Bromley Park Apartments)	WR-665, SUB 1	(01/21/2014)
Brookberry Park Apartments, LLC		
(Brookberry Park Apartments)	WR-798, SUB 7	(11/04/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION
Orders Issued *(Continued)*

Company	Docket No.	Date
Burd Properties Fayetteville, LLC		
(Carlson Bay Apartments)	WR-585, SUB 16	(06/02/2014)
(Stoney Ridge Apartments)	WR-585, SUB 17	(06/02/2014)
(Meadowbrook at King's Grant Apts.)	WR-585, SUB 18	(06/02/2014)
BVF Chambers Ridge Limited Partnership		
(Berkshires of Matthews Apts.)	WR-912, SUB 3	(04/07/2014)
BVF-II Providence Limited Partnership		
(Berkshires on Providence Apts.)	WR-913, SUB 3	(04/07/2014)
BVF Kensington Limited Partnership		
(Kensington Place Apts.)	WR-1245, SUB 1	(04/07/2014)
BVT Group, LLC		
(Bella Vista Townhomes Apts.)	WR-1396, SUB 1	(03/05/2014)
Caitlin Station Limited Partnership		
(Caitlin Station Apartments)	WR-180, SUB 4	(04/08/2014)
Cam Glen Apartments, LLC, et al.		
(Beacon Glen Apartments)	WR-1140, SUB 4	(07/30/2014)
Cambridge NC Warwick, LLC		
(Cambridge Apartments)	WR-514, SUB 6	(02/23/2014)
Cambridge on Elm, LLC		
(Cambridge on Elm Apartments)	WR-1260, SUB 2	(08/13/2014)
Cape Fear Multifamily, LLC		
(The Astoria at Hope Mills Apts.)	WR-1264, SUB 2	(09/22/2014)
Carlyle Centennial Parkside, LLC		
(Century Parkside Apartments)	WR-942, SUB 5	(08/29/2014)
Carlyle Place, LLC		
(Carlyle Place Apartments)	WR-647, SUB 1	(01/21/2014)
Carmel Valley II, LP		
(Marquis at Carmel Commons Apts.)	WR-71, SUB 7	(01/27/2014)
(Marquis at Carmel Commons Apts.)	WR-71, SUB 8	(12/23/2014)
CCC Brassfield Park, LLC		
(Brassfield Park Apartments)	WR-1619, SUB 1	(09/18/2014)
CCC Sommerset Place, LLC		
(Sommerset Place Apartments)	WR-1446, SUB 2	(12/08/2014)
CCSMCT, LLC		
(Sterling Magnolia Apartments)	WR-231, SUB 6	(09/29/2014)
Cedar Trace, LLC		
(Cedar Trace Apartments)	WR-897, SUB 6	(12/19/2014)
CEG Friendly Manor, LLC		
(Legacy at Friendly Manor Apts.)	WR-266, SUB 7	(07/21/2014)
Centennial Addington Farms, LLC		
(Century Trinity Estates Apartments)	WR-1403, SUB 2	(08/28/2014)

ORDER APPROVING TARIFF REVISION

<u>Orders Issued</u> (Continued)

Company	Docket No.	Date
Centennial Centerview, LP		
(Century Centerview Apartments)	WR-1272, SUB 2	(08/28/2014)
Central Pointe Apartments, LLC		
(Central Pointe Apartments)	WR-1479, SUB 1	(07/08/2014)
CH Realty V/Park and Market, LLC		
(Park and Market Apartments)	WR-1303, SUB 2	(09/18/2014)
Chapman; Roy & Betty		
(Twin Willows Mobile HP)	WR-1035, SUB 4	(12/23/2014)
Charleston Place, LLC		
(Charleston Place Apartments)	WR-700, SUB 3	(08/18/2014)
City View Apartments, LLC		
(City View at Southside Apts., Phase I)	WR-702, SUB 6	(12/19/2014)
City View Commercial, LLC		
(City View at Southside Apts., Phase II)	WR-1236, SUB 3	(12/19/2014)
CLNL Acquisition Sub, LLC		
(Colonial Village at South Tryon Apts.)	WR-975, SUB 36	(11/17/2014)
(Colonial Grand at Legacy Park Apts.)	WR-975, SUB 37	(11/17/2014)
(Colonial Village at Deerfield Apts.)	WR-975, SUB 38	(12/22/2014)
CMF 7 Portfolio, LLC		
(Colonial Grand at Huntersville Apts.)	WR-976, SUB 8	(11/17/2014)
(Colonial Village at Greystone Apts.)	WR-976, SUB 9	(11/17/2014)
CMF 15 Portfolio, LLC		
(Colonial Grand at Arringdon Apts.)	WR-955, SUB 24	(11/17/2014)
(Colonial Grand at Beverly Crest Apts.)	WR-955, SUB 25	(11/17/2014)
(Colonial Grand at Mallard Creek Apts.)	WR-955, SUB 26	(11/17/2014)
(Colonial Grand at Mallard Lake Apts.)	WR-955, SUB 27	(11/17/2014)
(Colonial Grand at Crabtree Apts.)	WR-955, SUB 28	(12/22/2014)
(Colonial Grand at Patterson Pl. Apts.)	WR-955, SUB 29	(12/22/2014)
CMLT 2008-LS1 Guilford Living, LLC		
(Ashley Oaks Apartments)	WR-1407, SUB 2	(09/03/2014)
CND Bridgeport, LLC		
(Bridgeport Apartments)	WR-751, SUB 2	(04/14/2014)
(Bridgeport Apartments)	WR-751, SUB 3	(10/06/2014)
CND Duraleigh Woods, LLC		
(Duraleigh Woods Apartments)	WR-741, SUB 5	(08/05/2014)
CND Sailboat Bay, LLC		
(Sailboat Bay Apartments)	WR-737, SUB 5	(08/05/2014)
Cogdill; Gregory S. & Narumon Feger		
(Rockola Mobile Home Park)	WR-935, SUB 6	(09/17/2014)
CoHeritage Oake Point, LLC		
(Oak Pointe Apartments)	WR-1316, SUB 2	(09/08/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Colonial Alabama Limited Partnership		
(Colonial Grand at Ayrsley Apts.)	WR-437, SUB 43	(11/17/2014)
(Colonial Village at Chancellor Park Apts.)	WR-437, SUB 44	(11/17/2014)
(Colonial Grand at University Center Apts.)	WR-437, SUB 45	(11/17/2014)
(Colonial Grand at Cornelius Apts.)	WR-437, SUB 47	(12/22/2014)
(Colonial Grand at Matthews Commons Apts.)	WR-437, SUB 48	(12/22/2014)
(Colonial Grand at Research Park Apts.)	WR-437, SUB 49	(12/22/2014)
(The Enclave Apartments)	WR-437, SUB 50	(12/22/2014)
Colonial NC, LLC		
(Colonial Townhouse Apartments)	WR-1284, SUB 3	(08/12/2014)
Commonwealth Road Properties, LLC		
(Enclave at Pamalee Square Apts.)	WR-1069, SUB 4	(06/10/2014)
Concord Five, LLC		
(Hampton Corners Apts.)	WR-579, SUB 4	(04/01/2014)
(Crown Ridge Apartments)	WR-579, SUB 7	(01/13/2014)
Copper Mill Village Apartments, LLC		
(Copper Mill Village Apartments)	WR-376, SUB 8	(08/29/2014)
Cornerstone NC Operating LP		
(Autumn Park Apartments)	WR-973, SUB 3	(11/17/2014)
Courtney at South Tryon, LLC		
(The Addison at South Tryon Apts.)	WR-1590, SUB 1	(12/29/2014)
Courtney Estates Grand, LLC		
(The Crossings at Alexander Pl. Apts.)	WR-729, SUB 5	(11/03/2014)
Courtney Estates Holdings, LLC		
(Courtney Estates Apartments)	WR-572, SUB 7	(08/05/2014)
Courtney Ridge H E, LLC		
(Courtney Ridge Apartments)	WR-321, SUB 8	(08/05/2014)
CREF Tribute, LLC		
(Tribute Apartments)	WR-1195, SUB 3	(09/08/2014)
Crescent Commons Apartments, LLC		
(Crescent Commons Apts.)	WR-460, SUB 7	(09/18/2014)
Crescent Oaks Apartments, LLC		
(Crescent Oaks Apartments)	WR-465, SUB 7	(12/23/2014)
Crestmont at Ballantyne Apartments, LLC		
(Crestmont at Ballantyne Apts.)	WR-335, SUB 10	(09/10/2014)
CRLP Bruckhaus Street, LLC		
(Colonial Grand at Brier Ck. Apts.)	WR-1060, SUB 3	(11/17/2014)
CRLP Crescent Lane, LLC		
(Colonial Village at Matthews Apts.)	WR-977, SUB 4	(11/17/2014)
CSHV Belmont, LLC		
(The Belmont Apartments)	WR-752, SUB 7	(09/22/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
CSP Fox Hollow, LLC		
(Fox Hollow Apartments)	WR-1187, SUB 2	(07/28/2014)
CSP Highland Oaks, LLC		
(Highland Oaks Apartments)	WR-1137, SUB 3	(12/31/2014)
CSP Hunt's View, LLC		
(Hunt's View Apartments)	WR-1217, SUB 3	(09/18/2014)
Cumberland Cove Apartments, LLC		
(Cumberland Cove Apartments)	WR-200, SUB 10	(07/21/2014)
CWS Carmel Valley Associates, LP, et al.		
(Marquis of Carmel Valley Apartments)	WR-1267, SUB 2	(01/27/2014)
(Marquis of Carmel Valley Apartments)	WR-1267, SUB 3	(12/23/2014)
CWSFG 91, LLC, et al.		
(Marquis at Preston Apartments)	WR-1207, SUB 3	(08/04/2014)
Deerwood Apartments, LLC		
(Twin City Apartments)	WR-853, SUB 4	(03/03/2014)
Delphil II, LLC		
(Veterans Park Apartments)	WR-991, SUB 1	(08/14/2014)
DLS Kernersville, LLC		
(Abbotts Creek Apartments)	WR-19, SUB 9	(07/14/2014)
(Abbots Creek Apartments)	WR-19, SUB 10	(10/27/2014)
Donathan/Briarleigh Park Properties, LLC		
(Briarleigh Park Apartments)	WR-797, SUB 7	(11/03/2014)
Donathan Cary Limited Partnership		
(Hyde Park Apartments)	WR-558, SUB 8	(07/28/2014)
Dowtin; James M.		
(Tall Pines Mobile Home Park)	WR-1577, SUB 1	(09/16/2014)
DPR Parc at University Tower, LLC		
(Parc at University Tower Apts.)	WR-1384, SUB 2	(08/04/2014)
DPR Southpoint Crossing, LLC		
(Southpoint Crossing Apartments)	WR-1385, SUB 2	(08/04/2014)
DRA Cypress Pointe, LP		
(Cypress Pointe Apartments)	WR-863, SUB 6	(09/19/2014)
DRA Lodge at Mallard Creek, LP		
(The Lodge at Mallard Creek Apts.)	WR-854, SUB 6	(09/10/2014)
DRA Quad, LP		
(Quad Apartments)	WR-871, SUB 5	(09/19/2014)
DRA Woodland Park, LP		
(Woodland Park Apartments)	WR-861, SUB 5	(09/19/2014)
Dry Ridge Properties, LLC, et al.		
(Mountain View Mobile Home Park)	WR-867, SUB 3	(09/17/2014)
Duckett; Gordon F. & Susan C.		
(Forest Ridge Mobile Home Park)	WR-928, SUB 6	(09/16/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Durham Holdings I, LLC		
(Amber Oaks Apartments)	WR-1467, SUB 1	(09/03/2014)
Durham Mews Section II Associates, LLC		
(The Mews Apartments, Section II)	WR-884, SUB 3	(12/03/2014)
Durham Section I Associates, LLC		
(The Mews Apts., Section I)	WR-883, SUB 3	(12/09/2014)
Dutch Village Apartments, LLC		
(Twin City Townhomes)	WR-865, SUB 4	(03/03/2014)
Eagle Point Village Apartments, LLC		
(Eagle Point Village Apartments)	WR-671, SUB 5	(02/05/2014)
(Eagle Point Village Apartments)	WR-671, SUB 6	(07/01/2014)
Eagle Property, LLC		
(Suffolk Place Apartments)	WR-1085, SUB 1	(06/09/2014)
East TBR Hamptons Owner, LLC		
(The Hamptons at Research Triangle Apts.)	WR-1370, SUB 1	(03/03/2014)
Echo Forest, LLC		
(Legacy Arboretum Apartments)	WR-368, SUB 10	(09/10/2014)
EEA Eastchester Ridge, LLC		
(Eastchester Ridge Apartments)	WR-509, SUB 7	(11/24/2014)
EEA-North Pointe, LLC		
(Sherwood Station Apartments)	WR-1028, SUB 3	(11/24/2014)
EEA-Wildwood, LLC		
(Wildwood Apartments)	WR-629, SUB 6	(11/24/2014)
Elizabeth Square Acquisition Corp.'		
(Elizabeth Square Apartments)	WR-1086, SUB 3	(08/04/2014)
Elon Crossing, LLC		
(Elon Crossing Apartments)	WR-1535, SUB 1	(09/17/2014)
ELPF Station Nine, LLC		
(Station Nine Apts.)	WR-724, SUB 6	(08/05/2014)
Erwin Hills Park, LLC		
(Erwin Hills Mobile Home Park)	WR-946, SUB 5	(08/14/2014)
Estate at Charlotte I, LLC		
(1420 Magnolia Apartments)	WR-73, SUB 6	(09/24/2014)
Ethan Pointe, LLC		
(Ethan Pointe Apartments)	WR-744, SUB 4	(10/27/2014)
Everest Brampton, LP		
(Brampton Moors Apartments)	WR-1091, SUB 3	(03/17/2014)
(Brampton Moors Apartments)	WR-1091, SUB 4	(08/11/2014)
Ewing; Roy and Frances		
(Pine Valley Mobile Home Park)	WR-994, SUB 5	(09/16/2014)
EWT 21, LLC		
(Wingate Townhouse Apartments)	WR-1354, SUB 2	(07/23/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Fairfield Courtney Place, LLC		
(Courtney Place Apartments)	WR-1598, SUB 1	(11/03/2014)
Fairfield Fairington, LLC		
(The Fairington Apartments)	WR-1418, SUB 2	(09/24/2014)
Fairfield Hamptons, LLC		
(The Hamptons at Southpark Apts.)	WR-1422, SUB 2	(08/19/2014)
Fairfield Mallard I, LLC		
(Bridges at Mallard Creek Apts., Phase I)	WR-1425, SUB 2	(08/19/2014)
Fairfield Mallard II, LLC		
(Bridges at Mallard Creek Apts., Phase II)	WR-1415, SUB 2	(08/19/2014)
Fairfield Marina Shores, LLC		
(Marina Shores Waterfront Apts.)	WR-1420, SUB 2	(09/08/2014)
Fairfield Oakbrook, LLC		
(Oakbrook Apartments)	WR-1423, SUB 2	(09/24/2014)
Fairfield Paces Commons, LLC		
(Paces Commons Apartments)	WR-1427, SUB 2	(08/19/2014)
Fairfield Quail Hollow, LLC		
(Bridges at Quail Hollow Apts.)	WR-1413, SUB 2	(09/24/2014)
Fairfield Waterford, LLC		
(Waterford Place Apartments)	WR-1424, SUB 1	(09/02/2014)
Fairway Apartments, LLC; The, et al.		
(The Links Apartments)	WR-565, SUB 5	(08/05/2014)
Falls River Apartments, LLC		
(Bell Falls River Apartments)	WR-1110, SUB 4	(09/18/2014)
FASF, LLC		
(Cedar Trace IV Apartments)	WR-999, SUB 5	(12/19/2014)
FC Glen Laurel, LLC		
(Glen Laurel Mobile HP)	WR-281, SUB 3	(07/28/2014)
FC Meadowbrook, LLC		
(Meadowbrook Mobile HP)	WR-280, SUB 6	(07/28/2014)
FCP West Village Phase I Owner, LLC		
(West Village Apartments)	WR-1251, SUB 3	(09/18/2014)
Featherstone Village Apartments, LLC		
(Featherstone Village Apartments)	WR-375, SUB 7	(02/05/2014)
(Featherstone Village Apartments)	WR-375, SUB 8	(08/29/2014)
Forest at Asheville Properties, LLC; The		
(Bell Forest at Biltmore Park Apts.)	WR-20, SUB 9	(09/18/2014)
Forest at Chasewood, LLC; The		
(The Forest at Chasewood Apts.)	WR-1504, SUB 1	(08/01/2014)
Forest Hill Apartments, LLC		
(The Reserve at Forest Hills Apts.)	WR-34, SUB 10	(07/21/2014)

ORDER APPROVING TARIFF REVISION

<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
Forest MMXII, LLC		
(Copper Creek Apartments)	WR-1367, SUB 2	(08/04/2014)
Forestdale Apartments, LLC		
(Hawthorne at Forestdale Apts.)	WR-1181, SUB 5	(10/20/2014)
Fortune Bay Associates, LLC		
(Forest Pointe Apartments)	WR-785, SUB 7	(08/25/2014)
(Forest Pointe Apartments)	WR-785, SUB 8	(10/14/2014)
Fuller Street Development, LLC		
(West Village Expansion Apts.)	WR-726, SUB 5	(09/18/2014)
Fund II Meadows, LLC, et al.		
(The Meadows Apts., Phase II)	WR-846, SUB 9	(09/22/2014)
Fund III Bridford Apartments, LLC		
(Bell Birdford Apartments)	WR-1120, SUB 3	(09/18/2014)
Fund III Cranbrook Apartments, LLC, et al.		
(Bell Biltmore Park Apartments)	WR-1076, SUB 4	(09/18/2014)
Fund IX CP Charlotte, LLC		
(Matthews Crossing Apartments)	WR-691, SUB 8	(08/11/2014)
Fund IX PR Durham, LLC		
(Pinnacle Ridge Apartments)	WR-518, SUB 9	(08/25/2014)
Fund X EBC Raleigh, LLC		
(Exchange at Brier Creek Apartments)	WR-1209, SUB 1	(02/24/2014)
(Exchange at Brier Creek Apartments)	WR-1209, SUB 2	(08/11/2014)
G Partnership, LP		
(The Landings Apartments)	WR-1262, SUB 1	(09/02/2014)
G&I VI Cape Harbor, LP		
(Cape Harbor Apartments)	WR-763, SUB 6	(09/19/2014)
G&I VI Clear Run, LP		
(Clear Run Apartments)	WR-762, SUB 7	(09/19/2014)
G&I VI Copper Mill, LP		
(Copper Mill Apartments)	WR-767, SUB 8	(09/19/2014)
G&I VI Crossing, LP		
(Crossing At Quail Hollow Apts.)	WR-764, SUB 8	(09/10/2014)
G&I VI Crosswinds, LP		
(Crosswinds Apartments)	WR-772, SUB 7	(09/19/2014)
G&I VI Harris Pond, LP		
(Harris Pond Apartments)	WR-771, SUB 8	(09/19/2014)
G&I VI Lake Lynn, LP		
(The Reserve at Lake Lynn Apts.)	WR-761, SUB 9	(09/19/2014)
G&I VI Liberty Crossing, LP		
(Liberty Crossing Apartments)	WR-760, SUB 5	(09/19/2014)
G&I VI Mallard, LP		
(Mallard Creek Apartments)	WR-776, SUB 8	(09/10/2014)

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
G&I VI Meadows at Kildare, LP		
(Meadows at Kildare Apartments)	WR-769, SUB 8	(09/19/2014)
G&I VI Mill Creek, LP		
(Mill Creek Apartments)	WR-774, SUB 7	(09/19/2014)
G&I VI Norcroft, LP		
(Northlake Apartments)	WR-768, SUB 8	(09/19/2014)
G&I VI Oaks at Weston, LP		
(Oaks at Weston Apartments)	WR-778, SUB 8	(09/19/2014)
G&I VI Providence Court, LP		
(Providence Court Apartments)	WR-758, SUB 8	(09/19/2014)
G&I VI Spring Forest, LP		
(Spring Forest Apartments)	WR-766, SUB 9	(09/19/2014)
G&I VI The Creek, LP		
(Sharon Crossing Apartments)	WR-770, SUB 14	(09/19/2014)
(The Creek Apartments)	WR-770, SUB 15	(09/19/2014)
G&I VI Walnut Creek, LP		
(Walnut Creek Apartments)	WR-777, SUB 9	(09/19/2014)
Galleria Partners II, LLC		
(The Crest Apartments at Galleria)	WR-925, SUB 2	(09/19/2014)
GECMC 2007-C1 Treetop Drive, LLC		
(Cumberland Trace Apartments)	WR-1126, SUB 3	(06/30/2014)
General Greene, LLC		
(Pinewood Apartments)	WR-486, SUB 4	(08/27/2014)
Genesis Partners, LLC		
(Treeside Mobile Home Park)	WR-323, SUB 10	(08/28/2014)
GF Property Funding Corp.		
(Garrett West Apartments)	WR-1534, SUB 1	(10/21/2014)
GGT Whitehall Venture NC, LLC		
(Whitehall Parc Apartments)	WR-1338, SUB 2	(09/23/2014)
Ginkgo BVG, LLC		
(Boundary Village Apartments)	WR-1519, SUB 1	(07/29/2014)
Ginkgo OBC, LLC		
(Oak Park at Briar Creek Apartments)	WR-1558, SUB 1	(07/08/2014)
Golden Triangle #1, LLC		
(Crest at Graylyn Apartments)	WR-1400, SUB 1	(09/17/2014)
Golden Triangle #3, LLC		
(Carmel on Providence Apts.)	WR-1439, SUB 2	(07/07/2014)
GQ Allerton, LLC		
(Allerton Place Apartments)	WR-1608, SUB 1	(09/22/2014)
Grace Park Development, LLC		
(Grace Park Apartments)	WR-893, SUB 5	(09/03/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued *(Continued)*

Company	Docket No.	Date
Granite Ridge Investments, LLC		
(Granite Ridge Apartments)	WR-295, SUB 5	(08/11/2014)
Greenville Village, LLC		
(Greenville Village Mobile HP)	WR-648, SUB 6	(06/09/2014)
Greenway at Fisher Park, LLC		
(Greenway at Fisher Park Apts.)	WR-1322, SUB 2	(08/15/2014)
Grey Eagle MHP, LLC		
(Grey Eagle Mobile Home Park)	WR-1546, SUB 1	(09/16/2014)
Greystone WW Company, LLC		
(Greystone at Widewaters Apartments)	WR-517, SUB 6	(07/15/2014)
Griffin and Sons Investments, LLC		
(Withrow Road Park, Section I)	WR-631, SUB 2	(02/10/2014)
GS Endinborough Commons, LLC		
(Edinborough Commons Apts.)	WR-475, SUB 9	(09/03/2014)
GS Edinborough Park, LLC		
(Edinborough at the Park Apts.)	WR-476, SUB 7	(09/03/2014)
GS Village, LLC		
(The Village Apartments)	WR-564, SUB 9	(09/03/2014)
Guardian Tryon Village, LLC		
(Windsor at Tryon Village Apts.)	WR-1335, SUB 2	(12/08/2014)
Hamilton Florida Partners, LLC		
(Hamilton Square Apts.)	WR-841, SUB 2	(08/18/2014)
Hampstead Investors, LLC		
(Hampstead Place Apartments)	WR-208, SUB 1	(02/20/2014)
(Hampstead Place Apts.)	WR-208, SUB 2	(04/07/2014)
Hanover Terrace, LLC		
(Hanover Terrace Apartments)	WR-622, SUB 7	(10/13/2014)
Happy Hill, Inc.		
(Willow Lake Mobile Home Park)	WR-512, SUB 3	(09/11/2014)
Harris Pointe, LLC		
(Harris Pointe Apartments)	WR-756, SUB 4	(03/24/2014)
(Harris Pointe Apartments)	WR-756, SUB 5	(08/06/2014)
HART Addison Park, LLC		
(Addison Park Apartments)	WR-1029, SUB 1	(08/27/2014)
Hawkins Street Holdings, LLC		
(Spectrum Apartments)	WR-1011, SUB 4	(12/03/2014)
Hawthorne-Midway Cadence, LLC		
(Hawthorne at the Peak Apts.)	WR-1485, SUB 1	(11/26/2014)
Hawthorne-Midway Dunhill, LLC		
(Hawthorne at the Trace Apartments)	WR-1430, SUB 1	(09/22/2014)
Hawthorne-Midway Madison Place, LLC		
(Madison Place Apartments)	WR-1300, SUB 3	(12/23/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

<u>*Orders Issued*</u> *(Continued)*

Company	Docket No.	Date
Hawthorne-Midway Meadows, LLC		
(Hawthorne at the Meadows Apts.)	WR-1307, SUB 3	(12/23/2014)
Hawthorne-Midway Meridian, LLC		
(Hawthorne at the Trail Apartments)	WR-1386, SUB 1	(03/18/2014)
Hawthorne-Midway Stratford, LLC, et al.		
(Hawthorne at the Parkway Apts.)	WR-1553, SUB 1	(10/20/2014)
Hawthorne-Midway Summerwood, LLC		
(Summerwood Apartments)	WR-1194, SUB 4	(12/23/2014)
Hawthorne-Midway Vista Park, LLC		
(Hawthorne at the Greene Apts.)	WR-1349, SUB 1	(10/20/2014)
Hayleigh Village Apartments, LLC		
(Hayleigh Village Apartments)	WR-1152, SUB 1	(02/04/2014)
(Hayleigh Village Apartments)	WR-1152, SUB 2	(08/28/2014)
Headwaters at Autumn Hall, LLC		
(Headwaters at Autumn Hall Apts.)	WR-1362, SUB 1	(11/25/2014)
Heather Ridge Apartments, LLC		
(Heather Ridge Apartments)	WR-356, SUB 5	(01/13/2014)
Heather Ridge Condominiums, LLC		
(Heather Ridge Condominiums)	WR-660, SUB 4	(01/13/2014)
Heatherwood Florida Partners, LLC		
(Heatherwood Trace Apartments)	WR-930, SUB 1	(08/18/2014)
Heinmiller Investments, LLC		
(Broadview Mobile Home Park)	WR-1092, SUB 4	(09/16/2014)
Henson Place, LLC		
(Henson Place Apartments)	WR-755, SUB 3	(12/03/2014)
Heritage Arden I, LLC, et al.		
(Arden Woods Apartments)	WR-1298, SUB 2	(09/03/2014)
Heritage at Arlington Apts., LLC; The		
(The Heritage at Arlington Apts.)	WR-1472, SUB 1	(11/18/2014)
Heritage Williamsburg I, LLC, et al.		
(Williamsburg Manor Apartments)	WR-1299, SUB 2	(09/03/2014)
Hidden Creek Village Apartments, LLC		
(Hidden Creek Village Apartments)	WR-377, SUB 7	(02/05/2014)
(Hidden Creek Village Apartments)	WR-377, SUB 8	(07/01/2014)
Highland Quarters, LLC		
(Muirfield Village Apartments)	WR-520, SUB 8	(06/23/2014)
Highlands at Olde Raleigh, LLC		
(Highlands at Olde Raleigh Apts.)	WR-1443, SUB 1	(09/15/2014)
Highpoint Associates, LLC		
(Laurel Bluff Apartments)	WR-570, SUB 2	(07/30/2014)
Holly NC, LLC		
(Holly Hills Apartments)	WR-1290, SUB 3	(08/13/2014)

ORDER APPROVING TARIFF REVISION

<u>Orders Issued</u> *(Continued)*

Company	Docket No.	Date
Horizon Development Properties, Inc.		
(Mill Pond Apartments)	WR-1075, SUB 1	(09/30/2014)
HTC Preston Reserve, LLC, et al.		
(Bell Preston Reserve Apartments)	WR-1180, SUB 3	(09/18/2014)
Inman Park Investment Group, Inc.		
(Inman Park Apartments)	WR-383, SUB 11	(08/08/2014)
Innesbrook Apartments, LLC		
(Southpoint Glen Apartments)	WR-1150, SUB 1	(12/01/2014)
Innisbrook Village, LLC		
(Innisbrook Village Apartments)	WR-1278, SUB 1	(02/04/2014)
(Innisbrook Village Apartments)	WR-1278, SUB 2	(08/28/2014)
Interurban Windsor, LLC		
(Windsor Harbor Apartments)	WR-1529, SUB 1	(11/04/2014)
Ivy Hollow Apartments, LLC		
(Ivy Hollow Apartments)	WR-299, SUB 5	(01/13/2014)
Joslin Realty, Inc.		
(Grove Park Apartments)	WR-151, SUB 9	(09/02/2014)
Juliet Place, LLC		
(Juliet Place Apartments)	WR-908, SUB 1	(12/15/2014)
KC Realty Investments, LLC		
(Woodland Heights Mobile HP)	WR-950, SUB 5	(09/17/2014)
Kings Park, LLC		
(Redcliffe at Kenton Place Apts.)	WR-349, SUB 11	(09/15/2014)
Kip-Dell Homes, Inc.		
(Clover Lane Townehomes)	WR-341, SUB 3	(08/14/2014)
Knickerbocker Properties, Inc. XX		
(Cheswyck at Ballantyne Apts.)	WR-109, SUB 15	(10/28/2014)
KPCLIC, LLC		
(Millbrook Green Apartments)	WR-573, SUB 7	(08/05/2014)
Kubeck; Bruce A.		
(Faircrest Mobile Home Park)	WR-310, SUB 31	(06/09/2014)
Lakeshore Apartments, LLC		
(The Lodge at Lakeshore Apts.)	WR-649, SUB 6	(12/19/2014)
Langtree HUD Development Co., LLC		
(Langtree Apartments)	WR-1477, SUB 1	(11/03/2014)
LaSalle NC, LLC		
(Duke Manor Apartments)	WR-1286, SUB 3	(08/13/2014)
Laurel Wood Associates, LLC		
(Laurel Wood MHP)	WR-1045, SUB 4	(09/16/2014)
Lawndale Associates, LLC		
(Winstead Commons Apartments)	WR-1253, SUB 1	(01/02/2014)

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Lees Chapel Partners, LLC		
(Chapel Walk Apartments)	WR-875, SUB 18	(12/19/2014)
(Cross Creek Apartments)	WR-875, SUB 19	(12/19/2014)
(Millbrook Apartments 2)	WR-875, SUB 20	(12/19/2014)
Legacy at Twin Oaks, LLC		
(Twin Oaks Apartments)	WR-1353, SUB 2	(07/25/2014)
Legacy Cornelius, LLC		
(Legacy Cornelius Apartments)	WR-1388, SUB 2	(09/09/2014)
Legacy Matthews, LLC		
(Legacy Matthews Apartments)	WR-568, SUB 8	(09/10/2014)
Legacy Oaks Apartments, LP		
(Alta Legacy Oaks Apartments)	WR-972, SUB 6	(08/05/2014)
(Alta Legacy Oaks Apartments)	WR-972, SUB 7	(10/06/2014)
Legacy Park, LLC		
(Legacy Park Apartments)	WR-646, SUB 1	(01/21/2014)
Legends at Hickory, LLC; The		
(The Legends Apartments)	WR-1409, SUB 2	(09/30/2014)
Lenoxplace Apartments, LLC		
(Lenox at Garners Station Apts.)	WR-1305, SUB 2	(08/06/2014)
Lincoln Green Apartments, LLC		
(Lincoln Green Apartments)	WR-527, SUB 6	(09/18/2014)
Litchford Park, LLC		
(The Park at North Ridge Apartments)	WR-588, SUB 8	(09/18/2014)
Lofts SREF at Lakeview, Inc.		
(Lofts at Lakeview Apartments)	WR-780, SUB 4	(08/05/2014)
Lone Oak, LLC		
(Lone Oak Mobile Home Park)	WR-1084, SUB 3	(09/29/2014)
Longview Apartments, LLC		
(Longview Meadow Apts.)	WR-825, SUB 4	(08/25/2014)
LVP Timber Creek, LLC		
(Beacon Timber Creek Apartments)	WR-717, SUB 7	(07/29/2014)
LVP Wendover, LLC		
(Camden Wendover Apartments)	WR-719, SUB 6	(07/29/2014)
M Realty, LLC		
(Wellington Mobile Home Park)	WR-1040, SUB 3	(06/30/2014)
Madison Properties, Inc.		
(673 Sand Hill Road Apartments)	WR-1380, SUB 5	(09/16/2014)
Maggard; David		
(Quite Hollow Mobile Home Park)	WR-632, SUB 5	(12/09/2014)
Mallard Glen Apartments, LLC		
(Mallard Glen Apartments)	WR-662, SUB 4	(01/13/2014)

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
Mallard Green, LLC		
(Mallard Green Apartments)	WR-1259, SUB 3	(08/25/2014)
Mallard Lake Apartments, LP		
(Mallard Lake Apartments)	WR-1089, SUB 3	(08/18/2014)
Marsh Realty Company		
(Park Place Apartments)	WR-1154, SUB 9	(03/10/2014)
(Biscayne Apartments)	WR-1154, SUB 10	(03/10/2014)
(Briarcreek Apartments)	WR-1154, SUB 11	(03/10/2014)
(Briarcreek Apartments)	WR-1154, SUB 12	(07/22/2014)
(Biscayne Apartments)	WR-1154, SUB 13	(07/22/2014)
(Park Place Apartments)	WR-1154, SUB 14	(07/22/2014)
Matthews Reserve, LLC		
(Matthews Reserve Apartments)	WR-557, SUB 4	(09/16/2014)
Mayfaire Apartments, LLC		
(Mayfaire Apartments)	WR-345, SUB 6	(08/14/2014)
MB Remington Place, LLC		
(Remington Place Apartments)	WR-461, SUB 8	(09/18/2014)
MB The Timbers, LLC		
(The Timbers Apartments)	WR-462, SUB 8	(09/18/2014)
McArthur Partners, LLC		
(The Heights at McArthur Park Apts., Phase I)	WR-1292, SUB 2	(10/07/2014)
McArthur Partners II, LLC		
(The Heights at McArthur Park Apts., Phase II)	WR-1124, SUB 3	(10/07/2014)
Mellow Field Partners, LLC		
(The Avenues Apartments)	WR-1564, SUB 1	(08/25/2014)
Meridian/HC, LLC		
(Legacy at Meridian Apartments)	WR-1500, SUB 1	(12/08/2014)
MFREVF-Piedmont, LLC		
(The Piedmont at Ivy Meadow Apts.)	WR-1190, SUB 2	(10/27/2014)
Mid-America Apartments, L.P.		
(Waterford Forest Apartments)	WR-22, SUB 60	(10/13/2014)
(Providence at Brier Creek Apts.)	WR-22, SUB 61	(10/13/2014)
(Hue Apartments)	WR-22, SUB 62	(10/13/2014)
(Hermitage at Beechtree Apts.)	WR-22, SUB 63	(10/13/2014)
(Brier Creek Apts., Phases I & II)	WR-22, SUB 64	(12/22/2014)
Morgan; Philip Edward		
(Clover Creek Village II MHP)	WR-1006, SUB 2	(02/03/2014)
Morganton Place Apartments, LLC		
(Morganton Place Apartments)	WR-782, SUB 3	(05/19/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Morganton Trading Company L.P.		
(Morganton Trading Company Apts.)	WR-548, SUB 3	(08/18/2014)
Morreene, LLC		
(Chapel Tower Apartments)	WR-1289, SUB 3	(08/12/2014)
Morrisville Associates, LLC		
(Crabtree Crossing Townhomes Apts.)	WR-879, SUB 3	(12/03/2014)
Moss; Allen H.		
(Maple Terrace Mobile Home Park)	WR-896, SUB 10	(08/06/2014)
(Crestview II Mobile Home Park)	WR-896, SUB 11	(08/06/2014)
Moss Enterprises, Inc. of Asheville		
(Mosswood/Twin Oak Mobile HP)	WR-924, SUB 12	(08/06/2014)
(Crownpointe Mobile Home Park)	WR-924, SUB 13	(08/06/2014)
Mosteller Apartments, LLC		
(Estates at Legends Apartments)	WR-1404, SUB 2	(09/30/2014)
Motley; Clyde J. & Carl K. Winkler		
(Indian Creek Mobile Home Park)	WR-1072, SUB 3	(08/07/2014)
Motley; Clyde J. & Sharon K.		
(Locust Grove Mobile Home Park)	WR-1071, SUB 3	(08/07/2014)
Mountain High Property Management, LLC		
(Becky's Mobile Home Park)	WR-1556, SUB 1	(09/16/2014)
MP Artisan Brightleaf Apartments, LLC		
(Artisan at Brightleaf Apts.)	WR-1478, SUB 2	(08/19/2014)
MP Beacon Glen, LLC		
(Beacon Glen Apartments)	WR-1665, SUB 1	(12/03/2014)
MP Creekwood, LLC		
(Village Lakes Apartments)	WR-738, SUB 6	(09/19/2014)
MP Cross Creek, LLC		
(Sardis Place at Matthews Apts.)	WR-736, SUB 6	(09/18/2014)
MP Hunt Club, LLC		
(Hunt Club Apartments)	WR-735, SUB 6	(09/18/2014)
MP Regatta, LLC		
(Regatta at Lake Lynn Apartments)	WR-1318, SUB 2	(09/18/2014)
MP The Oaks, LLC		
(The Oaks Apartments)	WR-734, SUB 6	(09/18/2014)
MP The Pointe, LLC		
(The Pointe Apartments)	WR-733, SUB 6	(09/18/2014)
MP The Regency, LLC		
(The Regency Apartments)	WR-740, SUB 6	(09/19/2014)
MP Winterwood, LLC		
(Aspen Peak Apartments)	WR-739, SUB 6	(09/10/2014)
MRWR, LLC		
(Atrium Apartments)	WR-832, SUB 7	(08/12/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued *(Continued)*

Company	Docket No.	Date
New Brentwood, LLC; The		
(Brentwood Apartments)	WR-1453, SUB 1	(09/02/2014)
Neyland Apartment Assoc. Two, LLC		
(Independence Park Apartments)	WR-1214, SUB 3	(08/14/2014)
NHE Tract H, LLC		
(Midtown Green Apartments)	WR-1612, SUB 1	(09/09/2014)
North Carolina Apartments I, LLC		
(Village Summit Apts.)	WR-1241, SUB 1	(04/07/2014)
North Carolina Rental Parks Assoc., Limited		
(Whispering Pines Mobile Home Park)	WR-1070, SUB 4	(09/30/2014)
North Timbers Associated L.P.		
(North Timbers Apartments)	WR-285, SUB 7	(02/18/2014)
Northland Governor's Point, LLC		
(Governor's Point Apartments)	WR-1257, SUB 1	(02/11/2014)
(Governor's Point Apartments)	WR-1257, SUB 2	(10/14/2014)
Northland River Birch, LLC		
(River Birch Apartments, Phase II)	WR-1258, SUB 1	(02/11/2014)
(River Birch Apartments, Phase II)	WR-1258, SUB 2	(10/14/2014)
Northland River Birch I, LLC		
(River Birch Apartments, Phase I)	WR-1248, SUB 1	(02/11/2014)
(River Birch Apartments, Phase I)	WR-1248, SUB 2	(10/14/2014)
Northland Windemere, LLC		
(Windemere Apartments)	WR-1369, SUB 1	(02/11/2014)
(Windemere Apartments)	WR-1369, SUB 2	(09/11/2014)
Norwalk Street Partners, LLC		
(Andover Park Apartments)	WR-653, SUB 6	(07/21/2014)
One Hilltop, LLC		
(Hilltop Mobile Home Park)	WR-1077, SUB 3	(12/02/2014)
ORP Lynnwood Park, LLC		
(Lynnwood Park Apartments)	WR-1186, SUB 2	(03/17/2014)
(Lynnwood Park Apartments)	WR-1186, SUB 3	(08/28/2014)
Park at Clearwater, LLC		
(Park at Clearwater Apts., Phases I & II)	WR-1167, SUB 3	(07/28/2014)
Park Commons MMXII, LLC		
(Parkland Commons Apartments)	WR-1366, SUB 2	(08/04/2014)
Park Forest Triad Apt. Portfolio, LLC		
(Park Forest Apartments)	WR-493, SUB 6	(09/18/2014)
Park Kingston Investors, LLC		
(Park and Kingston Apartments)	WR-1538, SUB 1	(07/23/2014)
Parkside Drive, LLC		
(CG at Brier Falls Apartments)	WR-1218, SUB 3	(12/22/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Passco Brier Creek DST		
(Carrington at Brier Creek Apts.)	WR-1614, SUB 1	(09/04/2014)
Passco Encore at the Park DST		
(Encore at the Park Apartments)	WR-1498, SUB 1	(08/04/2014)
Passco Rivergate DST		
(Enclave at Rivergate Apartments)	WR-1433, SUB 1	(09/15/2014)
Passco Wakefield Glen DST		
(Wakefield Glen Apartments)	WR-1582, SUB 1	(08/05/2014)
PC Links, LLC		
(Links at Citiside Apartments)	WR-1149, SUB 3	(07/07/2014)
Penwood Associates, LLC		
(Penwood Apartments)	WR-1448, SUB 2	(07/23/2014)
Perimeter Lofts Apartments, LLC		
(Perimeter Lofts Apts.)	WR-1468, SUB 1	(04/07/2014)
PG2, LLC		
(The Gardens at Anthony House Apts., Phase 2)	WR-1487, SUB 1	(12/19/2014)
Phillips Selwyn, LLC		
(3400 Selwyn Apartments)	WR-959, SUB 2	(09/23/2014)
Piper Glen Apartments Associates, LLC		
(Fairways at Piper Glen Apts.)	WR-252, SUB 4	(11/24/2014)
Piper Station Apartments, LLC		
(Piper Station Apartments)	WR-1432, SUB 2	(08/18/2014)
Plantation at Horse Pen, LLC		
(Plantation at Horse Pen Creek Apts.)	WR-1484, SUB 1	(11/26/2014)
Plantation Park Apartments, Inc.		
(Plantation Park Apartments)	WR-644, SUB 7	(08/05/2014)
Pleasant Garden Apartments, LLC		
(The Gardens at Anthony House Apts.)	WR-742, SUB 6	(12/19/2014)
POAA II, LLC		
(Pines of Ashton Apartments)	WR-1282, SUB 3	(08/13/2014)
Port City Investments, LLC		
(Village Green Apartments)	WR-1552, SUB 1	(10/06/2014)
Post Apartment Homes, LP		
(Post Uptown Place Apts.)	WR-49, SUB 16	(11/12/2014)
(Post Park at Phillips Place Apts.)	WR-49, SUB 17	(11/12/2014)
Post Ballantyne, LLC		
(Post Ballantyne Apartments)	WR-1543, SUB 1	(11/18/2014)
Post Parkside at Wade, LP		
(Post Parkside at Wade Apartments)	WR-1440, SUB 1	(11/10/2014)
Post South End, LP		
(Post South End Apartments)	WR-1326, SUB 2	(11/18/2014)

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
PR Oberlin Court, LLC		
(The Apartments at Oberlin Court)	WR-1179, SUB 2	(09/15/2014)
Princeton Park Apartments, LLC		
(Legacy North Hills Apartments)	WR-541, SUB 10	(09/10/2014
PRISA Southern Oaks NC, LLC		
(Southern Oaks at Davis Park Apts.)	WR-1176, SUB 1	(09/15/2014)
Privet Asheville, LLC		
(Eastwood Village Apartments)	WR-1320, SUB 2	(09/17/2014)
Providence Park Apartments, I, LLC		
(Providence Park Apartments)	WR-284, SUB 11	(07/23/2014)
Providence Park Properties, LLC		
(New Providence Park Apartments)	WR-840, SUB 3	(03/24/2014)
(New Providence Park Apts.)	WR-840, SUB 4	(08/07/2014)
Providence Pointe Apartments, LLC		
(Providence Pointe Apartments)	WR-715, SUB 1	(01/21/2014)
Prudential Insurance Company of America		
(The Reserve Apartments)	WR-38, SUB 8	(09/09/2014)
Puller Place Apartments, LLC		
(Puller Place at Carolina Forest Apts.)	WR-439, SUB 3	(09/30/2014)
Quadbridge HML Owner, LLC		
(Highland Mill Lofts Apts.)	WR-1613, SUB 1	(10/21/2014)
RAIA Properties NC-2, LLC		
(Birkdale Apartments Homes)	WR-839, SUB 7	(08/06/2014)
RAIA Self-Storage Montville, LLC, et al.		
(The Enclave at Crossroads Apts.)	WR-890, SUB 8	(08/06/2014)
Raleigh Multifamily Partners, LLC		
(Regency Place Apartments)	WR-1621, SUB 1	(09/18/2014)
Ramblewood Venture, LLC		
(Allister North Hills Apartments)	WR-1457, SUB 1	(04/21/2014)
(Allister North Hills Apartments)	WR-1457, SUB 2	(08/12/2014)
Ramsey; Emmett		
(Emma Hills Mobile Home Park)	WR-796, SUB 5	(10/01/2014)
Red Chief, LLC		
(Morehead Apartments)	WR-722, SUB 5	(10/29/2014)
REEP-MF Verde NC, LLC		
(North City 6 Apartments)	WR-1087, SUB 4	(08/04/2014)
Reserve at Mayfaire, LC; The		
(The Reserve at Mayfaire Apts.)	WR-387, SUB 6	(09/18/2014)
Retreat at Carrington Oaks, LLC		
(Hideaway Lake Apartments)	WR-1331, SUB 2	(06/24/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
RFI Highlands, LLC		
(The Highlands at Alexander Point Apartments)	WR-1294, SUB 2	(08/15/2014)
Richardson; John R. Real Estate IRA, LLC		
(245 Weaverville Hwy. Mobile HP)	WR-1133, SUB 2	(09/17/2014)
Ridge at Highland Creek, LLC		
(The Ridge at Highland Creek Apts.)	WR-1392, SUB 2	(07/29/2014)
Ridgeview MHP, LLC		
(Ridgeview Mobile Home Park)	WR-712, SUB 6	(09/16/2014)
Riverbend of Asheville, LLC		
(Verde Vista Apartments)	WR-1296, SUB 2	(09/23/2014)
Riverwoods Raleigh Apartments, LLC		
(Sterling Forest Apartments)	WR-1112, SUB 4	(10/07/2014)
Robinhood Court Apartment Homes, LLC		
(Robinhood Court Apartments)	WR-1051, SUB 5	(12/15/2014)
Rockwood Road Apts., LLC		
(Audubon Place Apartments)	WR-964, SUB 4	(12/01/2014)
Sagebrush Andover Woods Apartments, LLC		
(Andover Woods Apartments)	WR-1571, SUB 1	(10/07/2014)
Salem Village Apartments, LLC		
(Salem Village Apartments)	WR-446, SUB 8	(07/24/2014)
SBV-Greensboro-I, LLC		
(The Retreat I Apartments)	WR-1471, SUB 5	(09/02/2014)
(The Retreat II Apartments)	WR-1471, SUB 6	(09/02/2014)
SC Waterford Hills, LLC		
(Waterford Hills Apartments)	WR-1061, SUB 3	(10/13/2014)
Schrader Family Limited Partnership		
(Green Castle Apartments)	WR-980, SUB 6	(02/12/2014)
(Westcliffe Apartments)	WR-980, SUB 7	(02/12/2014)
(Dover Apartments)	WR-980, SUB 8	(02/12/2014)
(Peterson Park Apartments)	WR-980, SUB 9	(02/12/2014)
(Smithdale Apartments)	WR-980, SUB 12	(07/30/2014)
(Green Castle Apartments)	WR-980, SUB 13	(09/22/2014)
(Westcliffe Apartments)	WR-980, SUB 15	(09/22/2014)
(Peterson Park Apartments)	WR-980, SUB 16	(09/22/2014)
(Dover Apartments)	WR-980, SUB 17	(09/22/2014)
(Woodridge Apartments)	WR-980, SUB 18	(10/14/2014)
Schrader; Michael John		
(Campus West Apartments)	WR-795, SUB 1	(02/12/2014)
(Campus West Apartments)	WR-795, SUB 2	(09/22/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued *(Continued)*

Company	Docket No.	Date
Schrader Properties, LLC		
(Campus Courtyard Apartments)	WR-1334, SUB 1	(04/07/2014)
Seagrove Village MHP, LLC		
(Seagrove Village Mobile Home Park)	WR-1297, SUB 2	(07/29/2014)
SG-Waterford-Morrisville, LLC		
(The Waterford Apartments)	WR-1157, SUB 2	(02/10/2014)
(The Waterford Apartments)	WR-1157, SUB 3	(08/27/2014)
Sherwood MHP, LLC		
(Sherwood Mobile Home Park)	WR-1044, SUB 4	(08/14/2014)
Sherwood Place, LLC		
(Sherwood Place Apartments)	WR-723, SUB 3	(09/17/2014)
SHLP Chancery Village, LLC		
(Chancery Village at the Park Apts.)	WR-1204, SUB 3	(08/07/2014)
SHLP Gramercy Square at Ayrsley, LLC		
(Gramercy Square at Ayrsley Apts.)	WR-1184, SUB 3	(08/07/2014)
Silverton Marquis, LP		
(Marquis at Silverton Apartments)	WR-422, SUB 10	(08/26/2014)
Simpson Promenade Park, LLC		
(Promenade Park Apts.)	WR-876, SUB 3	(08/07/2014)
Simpson Woodfield Silos, LLC		
(Silos South End Apartments)	WR-1526, SUB 1	(08/07/2014)
Somerstone, LLC		
(Somerstone Apartments)	WR-1557, SUB 1	(08/08/2014)
South End Apartments, LLC		
(The Millennium South End Apts.)	WR-1173, SUB 3	(08/04/2014)
South Front, LLC		
(South Front Apartments)	WR-1134, SUB 1	(02/20/2014)
(South Front Apartments)	WR-1134, SUB 2	(08/07/2014)
South Square Owner, LLC		
(Alden Place at South Square Apts.)	WR-1387, SUB 2	(08/26/2014)
South Terrace Apartments North Carolina, LLC		
(South Terrace at Auburn Apts.)	WR-689, SUB 2	(01/02/2014)
Southbridge Multifamily, LLC		
(Stillwater at Southbridge Apts.)	WR-1390, SUB 1	(11/26/2014)
Southport Heather Ridge, LLC		
(Heather Ridge Apartments)	WR-1082, SUB 1	(03/17/2014)
(Heather Ridge Apartments)	WR-1082, SUB 2	(10/27/2014)
Spring Ridge Apartments, LLC		
(Hawthorne Northpark Apts.)	WR-725, SUB 5	(12/01/2014)
SRC Northwinds, Inc.		
(Northwinds I and II Apts.)	WR-1254, SUB 3	(09/11/2014)

ORDER APPROVING TARIFF REVISION
Orders Issued (Continued)

Company	Docket No.	Date
St. Andrews Place Apartments, LLC		
(Colonial Grand at Wilmington Apts.)	WR-111, SUB 10	(12/22/2014)
Steele Creek Apts. Property Owner, LLC		
(Park at Steele Creek Apartments)	WR-1332, SUB 1	(06/24/2014)
Steeplechase Triad Apt. Portfolio, LLC		
(Steeplechase Apartments)	WR-497, SUB 6	(09/18/2014)
Strawberry Hill Associates, LP		
(Strawberry Hills Apartments)	WR-293, SUB 9	(07/23/2014)
Strickland Farms Apartments, LLC		
(Strickland Farms Apartments)	WR-1304, SUB 3	(08/08/2014)
Strouse, Greenberg Properties VI LP		
(Tyvola Centre Apartments)	WR-983, SUB 2	(10/01/2014)
Summermill Properties, LLC		
(Summermill at Falls River Apts.)	WR-395, SUB 6	(07/16/2014)
Suncoast Cornerstone, LLC, et al.		
(Cornerstone Apartments)	WR-801, SUB 6	(02/17/2014)
Sunset Place, LLC		
(Sunset Place Apartments)	WR-1247, SUB 1	(09/17/2014)
Sureties Unlimited 2, LLC		
(Pinewood Trace Apartments)	WR-1377, SUB 2	(08/08/2014)
SVF Weston Lakeside, LLC		
(Apartments at Weston Lakeside)	WR-601, SUB 7	(08/05/2014)
Sweetwater Meadows, LLC		
(Sweetwater Meadows Mobile HP)	WR-1375, SUB 2	(09/16/2014)
Tau Valley, LLC		
(Tau Valley Apartments)	WR-823, SUB 3	(12/29/2014)
Thomasville Holly, LLC		
(Holly Hill Apartments)	WR-1607, SUB 1	(10/20/2014)
Three Oak Property, LLC		
(The Park at Three Oaks Apartments)	WR-405, SUB 3	(06/23/2014)
TIC Adams Farm, LLC, et al.		
(The Madison at Adams Farm Apts.)	WR-667, SUB 4	(10/01/2014)
TIC Bridford Lake, LLC, et al.		
(Bridford Lake Apartments)	WR-666, SUB 4	(10/01/2014)
Tiger Properties III, LLC		
(Arbor Creek Apartments)	WR-1102, SUB 3	(07/29/2014)
Timber Crest Apartments, LLC		
(Colonial Village at Timber Crest Apts.)	WR-412, SUB 8	(11/17/2014)
Town Square West, LLC		
(Biltmore Park Town Square Apts.)	WR-862, SUB 2	(06/04/2014)
TR Brier Creek, LLC		
(The Jamison at Brier Creek Apts.)	WR-1524, SUB 1	(08/25/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
TR Vinoy, LLC		
(The Vinoy at Innovation Park Apts.)	WR-1308, SUB 1	(01/06/2014)
(The Vinoy at Innovation Park Apts.)	WR-1308, SUB 2	(09/09/2014)
Tradition at Stonewater I, LP		
(The Tradition at Stonewater Apts., Ph. I)	WR-931, SUB 4	(08/05/2014)
Treybrooke, LLC		
(Treybrooke Apartments)	WR-824, SUB 2	(09/15/2014)
Treybrooke Village Apartments, LLC		
(Treybrooke Village Apartments)	WR-379, SUB 7	(02/05/2014)
(Treybrooke Village Apartments)	WR-379, SUB 8	(08/29/2014)
Triangle Real Estate of Gastonia, LLC		
(Bluff Ridge Apartments)	WR-1125, SUB 10	(09/11/2014)
(Huntersville Commons Apartments)	WR-1125, SUB 11	(10/08/2014)
(Eagle's Walk Apartments)	WR-1125, SUB 12	(10/08/2014)
Trinity Commons Apartments, LLC		
(Colonial Grand at Trinity Commons Apts.)	WR-415, SUB 8	(12/22/2014)
Triple Overlook, LLC		
(Triple Overlook MHP)	WR-1047, SUB 4	(08/14/2014)
TS Creekstone, LLC		
(Woodfield Creekside Apts.)	WR-1461, SUB 2	(08/27/2014)
TS New Bern, LLC		
(Fountains Southend Apartments)	WR-1541, SUB 1	(07/30/2014)
TS Westmont, LLC		
(Westmont Commons Apartments)	WR-1462, SUB 2	(07/30/2014)
VA Uptown, LLC		
(Uptown Gardens Apartments)	WR-1346, SUB 1	(10/28/2014)
VAC, LLLP		
(Briarwood Apartments)	WR-831, SUB 113	(08/12/2014)
(Chesterfield Apartments)	WR-831, SUB 114	(08/12/2014)
(Oakwood Apartments)	WR-831, SUB 115	(08/13/2014)
(Princeton Apartments)	WR-831, SUB 116	(08/13/2014)
(Rosewood Apartments)	WR-831, SUB 117	(08/13/2014)
(Eastwood Apartments)	WR-831, SUB 118	(08/13/2014)
Vanstory Apartments, LLC		
(Ashbrook Pointe Apartments)	WR-126, SUB 11	(07/21/2014)
Village at Cliffdale Apartments, LLC		
(Village at Cliffdale Apartments)	WR-842, SUB 3	(05/19/2014)
Village Rental Company, LLC		
(Villager Apartments)	WR-468, SUB 5	(09/02/2014)
Villas at Murrayville, LLC		
(Hawthorne at Murrayville Apts.)	WR-1221, SUB 2	(06/25/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
VR Cedar Springs Limited Partnership		
(Cedar Springs Apartments)	WR-1158, SUB 1	(03/17/2014)
(Cedar Springs Apartments)	WR-1158, SUB 2	(09/05/2014)
VTT Carver Pond, LLC		
(Meriwether Place Apartments)	WR-1509, SUB 1	(08/26/2014)
VTT Charlotte, LLC		
(Forest Ridge Apartments)	WR-1506, SUB 1	(09/17/2014)
VTT Durham, LLC		
(Foxfire Apartments)	WR-998, SUB 1	(03/11/2014)
(Foxfire Apartments)	WR-998, SUB 2	(08/26/2014)
VTT Greensboro, LLC		
(Brannon Park Apartments)	WR-1243, SUB 1	(03/24/2014)
Water Garden Village, LLC		
(Water Garden Village Apts.)	WR-1315, SUB 2	(09/09/2014)
Waterford Lakes Partners, LLC		
(Waterford Lakes Apartments)	WR-731, SUB 4	(07/11/2014)
Waterford Square Apartments Assoc., LLC		
(Waterford Square Apartments)	WR-251, SUB 7	(09/09/2014)
Waterlynn Ridge Apartments, LLC		
(Waterlynn Ridge Apartments)	WR-1360, SUB 1	(09/08/2014)
Waterstone Weddington Partners, LLC		
(Waterstone at Weddington Apts.)	WR-1583, SUB 1	(08/25/2014)
Waverly Apartments, LLC		
(The Waverly Apartments)	WR-1293, SUB 2	(08/11/2014)
Waypoint Stone Hollow Owner, LLC		
(Reserve at Stone Hollow Apts.)	WR-1611, SUB 1	(10/14/2014)
WBCMT 2006-C29 Cottage Place, LLC		
(Beechwood Apartments)	WR-1588, SUB 1	(09/03/2014)
Weirbridge Village Apartments, LLC		
(Weirbridge Village Apartments)	WR-1168, SUB 3	(12/09/2014)
Wellington United, LLC		
(Wellington Farms Apartments)	WR-1527, SUB 1	(07/28/2014)
West Market Partners, LLC		
(The Amesbury on West Market Apts.)	WR-749, SUB 6	(12/19/2014)
West Morgan, LLC		
(927 West Morgan Apartments)	WR-1428, SUB 2	(08/04/2014)
Westdale Arrowhead Crossing NC, LLC		
(Arrowhead Crossing Apartments)	WR-634, SUB 7	(07/24/2014)
Westdale Beech Lake, LLC		
(Beech Lake Apartments)	WR-1213, SUB 3	(08/26/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Westdale Brentmoor, LLC		
(Brentmoor Apartments)	WR-1317, SUB 2	(08/01/2014)
Westdale Chase on Monroe NC, LLC		
(Chase on Monroe Apartments)	WR-635, SUB 7	(08/26/2014)
Westdale Galleria Village, LLC		
(Galleria Apartment Homes)	WR-1224, SUB 3	(07/22/2014)
Westdale Lenox, LLC		
(Lenox at Patterson Place Apts.)	WR-1351, SUB 2	(08/26/2014)
Westdale NC Summit Creek, Ltd.		
(Johnston Creek Crossing Apartments)	WR-826, SUB 6	(07/24/2014)
Westdale Peppertree, Ltd.		
(Peppertree Apartments)	WR-815, SUB 6	(07/24/2014)
Westdale Poplar Place, LLC		
(Poplar Place Apartments)	WR-816, SUB 5	(03/24/2014)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 7	(07/24/2014)
Westdale Willow Glen NC, LLC		
(Willow Glen Apartments)	WR-633, SUB 7	(08/26/2014)
Westfield Thorngrove, LLC		
(Thorngrove Apartments)	WR-906, SUB 6	(09/17/2014)
Westridge Village, LLC		
(Westridge Village Apts.)	WR-1142, SUB 1	(09/17/2014)
Whitehurst/Countryview Mobile Home Park, LLC		
(Whitehurst/Countryview Mobile HP)	WR-657, SUB 1	(08/18/2014)
Willow Rentals, LLC		
(Willow Trail Mobile HP)	WR-1569, SUB 1	(09/15/2014)
Wilmington Student Housing, LLC		
(Campus Walk I Apartments)	WR-1431, SUB 1	(10/07/2014)
Windsor Landing Investments I, LLC, et al.		
(Windsor Landing Apartments)	WR-886, SUB 4	(12/19/2014)
Winkler; Carl K.		
(Mulberry Hill Mobile Home Park)	WR-887, SUB 4	(08/07/2014)
Winstead Warehousing, LLC		
(Hawthorne Crossing Apartments)	WR-1222, SUB 3	(11/26/2014)
WMCi Charlotte I, LLC		
(Bexley Commons at Rosedale Apts.)	WR-213, SUB 12	(07/08/2014)
WMCi Charlotte II, LLC		
(Bexley Creekside Apartments)	WR-230, SUB 11	(07/08/2014)
WMCi Charlotte III, LLC		
(Bexley at Lake Norman Apts.)	WR-258, SUB 11	(07/09/2014)
WMCi Charlotte IV, LLC		
(Bexley Crossing at Providence Apts.)	WR-269, SUB 11	(07/09/2014)

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
WMCi Charlotte V, LLC		
(Bexley at Springs Farm Apts.)	WR-340, SUB 10	(07/09/2014)
WMCi Charlotte VI, LLC		
(Bexley Square at Concord Mills Apts.)	WR-371, SUB 6	(07/14/2014)
WMCi Charlotte VII, LLC		
(Bexley at Davidson Apartments)	WR-392, SUB 9	(07/09/2014)
WMCi Charlotte VIII, LLC		
(Bexley at Matthews Apartments)	WR-466, SUB 9	(07/09/2014)
WMCi Charlotte IX, LLC		
(Bexley Greenway Apartments)	WR-467, SUB 9	(07/10/2014)
WMCi Charlotte X, LLC		
(Bexley Harborside Apartments)	WR-638, SUB 7	(07/10/2014)
WMCi Charlotte XI, LLC		
(Bexley at Steelecroft Apartments)	WR-1117, SUB 4	(07/07/2014)
WMCi Charlotte XII, LLC		
(Bexley Cloisters at Steelecroft Apts.)	WR-1136, SUB 3	(07/07/2014)
WMCi Charlotte XIII, LLC		
(Bexley Village at Concord Mills Apts.)	WR-1189, SUB 2	(07/14/2014)
WMCi Charlotte XIV, LLC		
(Bexley Village at Concord Mills II Apts.)	WR-1474, SUB 1	(07/14/2014)
WMCi Charlotte XV, LLC		
(Cielo Apartments)	WR-1486, SUB 1	(07/08/2014)
WMCi Raleigh I, LLC		
(Bexley at Preston Apartments)	WR-327, SUB 9	(08/06/2014)
WMCi Raleigh II, LLC		
(Bexley Park Apartments)	WR-317, SUB 9	(07/24/2014)
WMCi Raleigh III, LLC		
(Bexley at Brier Creek Apartments)	WR-754, SUB 10	(08/25/2014)
WMCi Raleigh IV, LLC		
(Bexley at Heritage Apts.)	WR-803, SUB 4	(08/25/2014)
WMCi Raleigh V, LLC		
(Bexley at Carpenter Village Apts.)	WR-949, SUB 6	(08/06/2014)
WMCi Raleigh VI, LLC		
(Bexley at Triangle Park Apartments)	WR-1311, SUB 2	(07/23/2014)
WMCi Raleigh VIII, LLC		
(Bexley Panther Creek Apartments)	WR-1372, SUB 2	(07/23/2014)
Woodberry Asheville Apartments, LLC		
(Woodberry Apartments)	WR-791, SUB 5	(10/29/2014)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION

Orders Issued (Continued)

Company	Docket No.	Date
Woodlake Downs Associates Limited Partnership		
(Woodlake Downs Apartments)	WR-286, SUB 11	(02/17/2014)
Woodland Heights of Burlington, LLC		
(Woodland Heights Apartments)	WR-1050, SUB 2	(03/10/2014)
(Woodland Heights Apartments)	WR-1050, SUB 3	(12/22/2014)
WRT Lake Brandt Property, LLC		
(Lake Brandt Apartments)	WR-1368, SUB 1	(10/27/2014)
WW Partnership		
(Blue's Crossing Apartments)	WR-850, SUB 4	(08/27/2014)
Wynslow Park, LLC		
(Gardens at Wynslow Park Apts.)	WR-128, SUB 4	(08/06/2014)
Yorktowne Apartments, LLC		
(Yorktown Club Apartments)	WR-1128, SUB 3	(07/29/2014)
2 Hiltin Place Greensboro, LLC		
(Park Place Apartments)	WR-1473, SUB 1	(10/13/2014)
100 Spring Meadow Drive Apts. Investors, LLC		
(Alta Springs Apartments)	WR-47, SUB 10	(08/04/2014)
330 West Tremont, LLC		
(335 Apartments)	WR-1548, SUB 1	(10/06/2014)
1300 Knoll Circle Apts. Investors, LLC		
(The Lodge at Southpoint Apts.)	WR-268, SUB 9	(09/09/2014)
4209 Lassiter Mill Road Apts. Investors, LLC		
(Alexan North Hills Apartments)	WR-571, SUB 5	(08/05/2014)
5205 Barbee Chapel Road Apts. Investors I, LLC		
(Springs of Chapel Hill Apartments)	WR-1505, SUB 1	(08/04/2014)
7850 Cottage Cove, LLC		
(Cottage Cove Mobile Home Park)	WR-1196, SUB 1	(03/03/2014)
7850 Homestead Village, LLC		
(Homestead Village Mobile Home Park)	WR-1197, SUB 2	(03/03/2014)

East TBR Hamptons Owner, LLC -- WR-1370, SUB 1; Reissued Order Approving Tariff Revision *(The Hamptons at Research Triangle Apartments)* (03/06/2014)

Ginkgo BVG, LLC – WR-1519, SUB 1; Errata Order *(Boundary Village Apartments)* (07/30/2014)

Grey Eagle MHP, LLC – WR-1546, SUB 0; WR-1254, SUB 2; Errata Order *(Grey Eagle Estates MHP)* (08/11/2014)

Happy Hill, Inc. -- WR-512, SUB 3; Reissued Order Approving Tariff Revision *(Willow Lake Mobile Home Park)* (09/12/2014)

Heinmiller Investments, LLC -- WR-1092, SUB 4; Errata Order *(Broadview Mobile Home Park)* (09/18/2014)

Highland Quarters, LLC -- WR-520, SUB 8; Reissued Order Approving Tariff Revision *(Muirfield Village Apartments)* (06/27/2014)

<u>WATER RESELLERS – Tariff Revision for Pass-Through</u> *(Continued)*

JLB Southline, LLC -- WR-1376, SUB 1; Errata Order *(Junction 1504 Apartments)* (05/09/2014)

MP Artisan Brightleaf Apartments, LLC -- WR-1478, SUB 1; Order Allowing Withdrawal *(Artisan at Brightleaf Apartments)* (08/04/2014)

North Carolina Apartments I, LLC -- WR-1241, SUB 1; Reissued Order Approving Tariff Revision *(Village Summit Apartments)* (04/08/2014)

Northland River Birch, LP -- WR-1258, SUB 1; Errata Order *(River Birch Apartments, Phase II)* (03/21/2014)

Passco Wakefield Glen DST -- WR-1582, SUB 1; Errata Order *(Wakefield Glen Apts.)* (08/06/2014)

PC Links, LLC -- WR-1149, SUB 4; Errata Order *(Links at Citiside Apartments)* (07/07/2014)

Wynslow Park, LLC -- WR-128, SUB 3; Errata Order *(Gardens at Wynslow Park Apts.)* (01/15/2014)

ORDER APPROVING TARIFF REVISION (HWCCWA)

<u>Orders Issued</u>

Company	Docket No.	Date
Brentwood West Company, LLC		
(Brentwood West Apartments)	WR-1160, SUB 4	(09/04/2014)
Brook Dana, LLC		
(Brook Hill Apartments)	WR-1281, SUB 4	(08/13/2014)
CSC Midtown, LLC		
(Midtown Park Apartments)	WR-1482, SUB 1	(12/08/2014)
EWT 22, LLC		
(The Willows Apartments)	WR-1329, SUB 2	(07/23/2014)
Fairfield Woods Edge, LLC		
(Woods Edge Apartments)	WR-1417, SUB 1	(09/09/2014)
Fund II Meadows, LLC, et al.		
(The Meadows Apartments, Phase I)	WR-846, SUB 10	(09/22/2014)
G&I VI Brynn Marr, LP		
(Brynn Marr Village Apartments)	WR-759, SUB 5	(09/19/2014)
G&I VI Forest Hills, LP		
(Forest Hills Apartments)	WR-968, SUB 5	(09/19/2014)
Hawthorne-Midway Turtle Creek, LLC		
(Hawthorne at Southside Apartments)	WR-1497, SUB 1	(08/28/2014)
Heritage Lakes I, LLC, et al.		
(The Lakes Apartments)	WR-1202, SUB 2	(09/08/2014)
Honeytree Acquisitions, LLC		
(Honeytree Apartments)	WR-1545, SUB 1	(09/04/2014)
HR Realty Company, LLC		
(Hunting Ridge Apartments)	WR-1161, SUB 4	(09/04/2014)
Montecito Company, LLC		
(Montecito Apartments)	WR-1162, SUB 4	(09/04/2014)

ORDER APPROVING TARIFF REVISION (HWCCWA)
Orders Issued *(Continued)*

Company	Docket No.	Date
PC Oxford, LLC		
(Oxford Square Apartments)	WR-1383, SUB 2	(07/29/2014)
QR Realty Company, LLC		
(Quail Ridge Apartments)	WR-1159, SUB 4	(09/04/2014)
Schmitz; Robert L.		
(1212 Chapel Hill Street Apts.)	WR-1249, SUB 4	(08/19/2014)
Schrader Family Limited Partnership		
(Cedar Point Apartments)	WR-980, SUB 14	(09/22/2014)
Shellbrook Associates, LP		
(Shellbrook Apartments)	WR-1192, SUB 4	(09/04/2014)
Signature Place, LLC		
(Signature Place Apartments)	WR-1074, SUB 2	(08/14/2014)
Sumare Limited Partnership		
(Sumter Square Apartments)	WR-1163, SUB 5	(09/08/2014)
West Montecito Company L.P.		
(Montecito West Apartments)	WR-1164, SUB 4	(09/04/2014)

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