NINETY-EIGHTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2008 THROUGH DECEMBER 31, 2008

NINETY-EIGHTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2008, through December 31, 2008

Edward S. Finley, Jr., Chairman

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner[1]

Howard N. Lee, Commissioner

William T. Culpepper, III, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Ms. Renné Vance
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

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

[1] Commissioner Kerr resigned from the Commission effective August 31, 2008

LETTER OF TRANSMITTAL

December 31, 2008

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, 2008, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2008, and ending December 31, 2008.

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

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

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William T. Culpepper, III, Commissioner

Renné Vance, Chief Clerk

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DOCKET NO. P-100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Lifeline and Link-Up Service Pursuant to Section 254 of the Telecommunications Act of 1996	)))	ORDER ADOPTING LIFELINE/LINK-UP PROGRAM EXPANSION

BY THE COMMISSION: On January 15, 2008, the Lifeline/Link-Up Task Force (Task Force) submitted its semi-annual report and recommendations in response to the Commission's *Order Requesting Further Study to Adopt Lifeline/Link-Up Program Expansion* issued on August 4, 2005.

On January 16, 2008, the Commission issued its Order requesting interested persons to file comments on the Task Force's recommendations by no later than February 22, 2008, and reply comments by no later than March 7, 2008.

On February 21, 2008, and February 22, 2008, Public Staff and Sprint Nextel Corporation (Sprint Nextel) filed comments in this docket, respectively.

On March 7, 2008, the Task Force and Sprint Nextel Corporation filed reply comments in this docket.

TASK FORCE REPORT SUMMARY

The Task Force reported that, based on the most recent statistics filed by local telephone providers prior to the time of this report, as of December 31, 2007, there were 118,204 households receiving Lifeline benefits. In addition, during the period July 1, 2007, through December 31, 2007, there were 3,012 households that have received Link-Up discounts for the cost of connecting telephone service. The Task Force stated that, in comparison, the June 2007 reports filed by local telephone service providers reflected 121,228 Lifeline recipients as of June 30, 2007. Furthermore, the June 2007 reports showed that, from January 1, 2007, through June 30, 2007, there were 3,022 households that received Link-Up discounts.

Since the Task Force's previous report to the Commission, the Task Force has pursued the implementation of streamlining the enrollment procedure for recipients of Food and Nutrition Services (Food Stamps). Also, the Task Force reported that it has not implemented AT&T's pilot self-certification procedure. In addition to the implementation of these two projects, the Task Force is recommending, as an additional channel to increase program participation, that the existing eligibility criteria for persons receiving Section 8 federal housing assistance be expanded to include recipients of federal public housing.

Specifically, with regard to streamlining the enrollment process for Food Stamp recipients, the Task Force explained that, once a person is found eligible to receive Food Stamps, Medicaid, Work First, Supplemental Security Income (SSI), Low Income Energy Assistance Program (LIHEAP), or Section 8 housing, (hereinafter collectively referred to as qualifying benefit programs), the person is automatically eligible to receive Lifeline/Link-Up benefits. The Task Force also pointed out that the county Department of Social Services (DSS) offices are responsible for receiving applications and for verifying eligibility for all of the qualifying benefit programs except Section 8 housing and SSI. Section 8 is a U. S. Department of Housing and Urban Development (HUD) program, which is administered by various local agencies; and, SSI is administered by the Social Security Administration.

The Task Force commented that the eligibility and enrollment data for all of the qualifying benefit programs, except Section 8 housing, are maintained by the North Carolina Department of Health and Human Services (DHHS). The Task Force further commented that DHHS and the telephone companies exchange information about persons who are eligible for qualifying benefit programs and Lifeline/Link-Up.

The Task Force explained that, for Lifeline/Link-Up enrollment purposes, the present system requires two additional steps after a person has been interviewed and determined to be eligible for a qualifying benefit program. First, the DSS caseworker and applicant must complete and sign an application form for the telephone discount. Second, the caseworker must send the completed form to the applicant's local telephone company.

The Task Force has been working towards eliminating these two steps for Food Stamp recipients. The Task Force stated that these steps could be eliminated by having DHHS provide each local telephone company with a list of its customers who have been found eligible to receive Food Stamps and thus who also are eligible to receive Lifeline benefits. Each company would then match the DHHS eligibility file with its customer account records and identify persons eligible for the discount but not receiving it. As a result of this process, the company would then automatically grant the lifeline discount to those persons starting with the next billing cycle.

The Task Force suggested that this streamlined enrollment procedure for Food Stamp recipients would require three major changes from the current procedures. First, the name of the applicant's telephone company and the applicant's telephone number must be recorded on the Food Stamp application form. Second, this information must be recorded on the Food Stamp computer records. Third, an electronic file must be created for each telephone company containing the names and phone numbers of Food Stamp recipients receiving service from that company, then mailed or sent electronically to the Lifeline/Link-Up coordinator of each company.

The Food Stamp application form and computer records have been modified to include the applicant's telephone number, a code identifying the applicant's telephone company, and a code designating the applicant's service as wire or wireless. These three fields of information were added to the Food Stamp computer program, and in August 2007 the new procedures were implemented in all DSS offices.

The Task Force stated that, during the first four months that the new procedures were used, about 102,000 applicants' telephone numbers were identified as qualifying for Lifeline benefits. However, only about 32,000 of those applicants identified provided the name of their local telephone company. In approximately 70,000 of the records identified, the local telephone company was coded as "99", which is the code for an unknown or undesignated company. The Task Force reported that DHHS will need to refine the procedures to ensure more complete data before the streamlined enrollment system will function effectively.

Also, DHHS has been working with a secure file transfer protocol (FTP) that allows DHHS and the telephone companies to transfer Lifeline/Link-Up eligibility information over a secured internet connection instead of by mail. The Task Force stated that DHHS has been successful in using FTP to review eligibility files with several companies; however, questions remain about the mechanics of this procedure, including the amount and frequency of information to be exchanged.

The Task Force also reported that similar changes in the enrollment process are being pursued for Medicaid recipients. Although the Medicaid application has been modified to include information for Lifeline enrollment, the computer program supporting the Medicaid program currently does not have the capacity to add this information to its files. The Task Force stated that changes in the Medicaid enrollment process do not appear likely to take place in the near term.

The Task Force also commented on the Commission's approval of the AT&T self-certification pilot study, stating that the Commission ordered one change in the self-certification form and directed AT&T to report certain information at the completion of the pilot study. The Task Force reported that, although AT&T has revised the self-certification form, as directed, and is ready to implement the pilot study, the Task Force decided to wait until after the Commission decides on whether to approve the addition of federal public housing participation as an eligibility criterion for Lifeline/Link-Up before commencing the AT&T pilot.

Also, the Task Force stated that, under the Lifeline/Link-Up guidelines, it is permissible for a state to use both Section 8 assistance and federal public housing as eligibility criteria. The Task Force noted that federal public housing typically involves an apartment facility owned by a public housing authority and dedicated solely to housing for low-income individuals and families. The Task Force stated that the Commission's present guidelines appear to limit Lifeline/Link-Up eligibility to persons receiving Section 8 support. The Task Force is now recommending that the Commission extend Lifeline/Link-Up eligibility to persons receiving federal public housing. The Task Force stated that recipients in both Section 8 and federal public housing programs can afford to pay no more than 30% of their income on housing, which is a common factor for eligibility to participate in each program. Therefore, the Task Force suggested that there is logic and fairness in treating all such persons equally in regards to Lifeline/Link-Up eligibility.

According to HUD, there are 39,000 federal public housing units in North Carolina. The Task Force noted that there are many families living in federal public housing that work low wage jobs that makes them ineligible for Food Stamps and other qualifying benefits. Nevertheless, the Task Force believed that these low income families could benefit substantially from a discount on their phone bills.

The Task Force noted that DHHS has no data link to HUD that will allow streamlined enrollment and eligibility reviews for housing program participants. However, since the same barrier applies to Section 8 participants, the lack of a data link does not present an insurmountable barrier. The Task Force stated that, based on the Commission's goal of increasing participation in the Lifeline/Link-Up program, the Task Force believes that the Commission should revise the eligibility criteria to include recipients of federal public housing.

The Task Force also reported that it continues to publicize the Lifeline/Link-Up program by distributing brochures, by including information in telephone directories, and by providing inserts in telephone bills. Also, the Task Force is working with AT&T in design of posters, the cost of which is being absorbed by AT&T. These posters will be placed in each of the DSS offices throughout the State.

COMMENTS

Sprint Nextel commented that the measures to eliminate unnecessary steps or to streamline the process of Lifeline enrollment may be problematic. Sprint Nextel stated that the process currently under review would require eligible telecommunications carriers (ETCs) to apply the Lifeline credit automatically to the customer's bill even if the customer does not subscribe to the service plan that has been designated as the Lifeline plan, which federal law defines as the lowest generally available residential rate plan. Furthermore, the telephone company (ETC) would automatically grant the Lifeline discount to those persons starting with the next billing cycle.

Sprint Nextel's first concern was that the process appears to require ETCs to apply the Lifeline credit even though the customer may not be subscribing to the service plan that has been designated as the Lifeline plan, which federal law defines as the lowest generally available residential rate plan. Sprint Nextel stated that the phone company would automatically grant the Lifeline discount to those persons starting with the next billing cycle, based on their qualifying for the discount, although they may not be subscribing to the lowest available residential (i.e., wireless) rate plan. Additionally, Sprint Nextel stated that the customer may also be entitled to additional Lifeline credit if living on federally recognized tribal land. Sprint Nextel characterized the automatic crediting of Lifeline discounts to a customer account as "analogous to slamming".

Secondly, Sprint Nextel stated that, based on FCC and federal rules and regulations, all ETCs must apply the federal Lifeline support discounts to reduce the cost of the carrier's lowest residential rate. Sprint Nextel was concerned that the proposed process requires ETCs to apply the federal Lifeline support to the cost of any and all residential rates and thus may be inconsistent with federal law.

Thirdly, Sprint Nextel commented that, "because 47 C.F.R. Section 54.403(b) prohibits an ETC from applying federal Lifeline assistance to reduce the cost of any rate plan other than the carrier's lowest cost, generally available rate plan, an ETC could not properly seek reimbursement from the federal universal service fund for discounts required to be applied to premium plans". Sprint Nextel suggested that the Task Force's streamlined enrollment process would therefore constitute state wireless rate regulation in violation of 47 U.S.C. Section 332(c)(3)(A).

The Public Staff commented that, through the efforts of the Task Force, it has learned that both the FCC and Universal Service Administrative Company (USAC) recognize federal housing as well as Section 8 housing assistance for Lifeline/Link-Up eligibility. The Public Staff pointed out that since the Commission has stated its objective to increase the level consumer participation in the Lifeline/Link-Up program, expanding the eligibility to include federal public housing should be beneficial in achieving the goal of increased participation across the State.

The Public Staff recommended that the Commission adopt the Task Force's recommendation to expand the Lifeline/Link-Up eligibility criteria and direct the affected telephone companies to file appropriate tariffs to reflect this expansion. The Public Staff also recommended that NCUC Rule R9-6(c)(2) be rewritten to read as follows:

> (2) In order to be eligible for assistance, a residential subscriber must be a current recipient of Supplemental Security Income, Foods Stamps, Medicaid, Low Income Home Energy Assistance Program (LIHEAP), federal public housing and Section 8 housing assistance ~~(Section 8)~~, or a current participant in Work First or Temporary Assistance for Needy Families; ~~provided, however, that LIHEAP and federal public housing assistance (Section 8) shall not become effective as eligibility criteria herein until April 3, 2000.~~

REPLY COMMENTS

Sprint Nextel stated in its reply comments that it supports the expansion of the existing Lifeline/Link-Up eligibility criteria recommended by the Public Staff in its initial comments.

The Task Force observed that Sprint Nextel and Public Staff had filed comments. The Task Force noted with approval that the Public Staff had filed comments supporting the addition of federal public housing as an eligibility criterion and proposing an amendment to Commission Rule R9-6(c)(2) to implement the change.

The Task Force's reply with respect to Sprint Nextel's comments was more pointed. Sprint Nextel did not address the Task Force's recommendation to expand the Lifeline/Link-Up eligibility criteria to include recipients of federal public housing. The Task Force noted that Sprint Nextel challenged the Commission's decision to streamline the enrollment and eligibility review procedures for Food Stamp recipients. The Task Force stated that Sprint Nextel's comments were inapposite for two reasons.

First, the Task Force stated that its sole recommendation in the semi-annual report to the Commission was to request that the Commission add federal public housing as a Lifeline/Link-Up eligibility criterion. As such, this was the only relevant issue for comment.

Secondly, the Task Force stated that the essence of Sprint Nextel's comments was to suggest that the Commission rescind its decision in its September 5, 2007, *Order Concerning Task Force Report and Authorizing Pilot.* This Order was a continuation of the process streamlining the enrollment process for Lifeline/Link-Up benefits and a review of the procedures for Food Stamp recipients as addressed in the Commission's *Order Requesting Further Study to Adopt Lifeline/Link-Up Program Expansion*, dated August 4, 2005. As such, the Task Force's semi-annual report of January 15, 2008, addressed implementing changes in the enrollment processes, which have been under review since last August, 2007.

The Task Force commented that Sprint Nextel has not demonstrated that the Commission's previous Order should be rescinded. The crux of Sprint Nextel's comments is that an ETC can serve Lifeline participants only on the ETC's lowest-cost base rate plan. Therefore, if a Sprint Nextel subscriber is found to qualify for Lifeline benefits but subscribes to a service plan other than "basic", then switching the service plan to "basic" is required. The Task Force stated that, under Sprint Nextel's reasoning, the Food Stamp streamlined enrollment process is not workable.

The Task Force believed that the FCC rules and orders cited in Sprint Nextel's comments are not on point. The Task Force observed that Sprint Nextel would dictate that Lifeline recipients cannot choose the level of service they desire. The Task Force concluded that restricting service plan choices would be contrary to the Commission's goal of increasing participation in Lifeline, inasmuch as it could discourage eligible customer from applying for Lifeline assistance.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that the Lifeline/Link-Up program should be revised to amend the eligibility criteria to include recipients of federal public housing. The Commission agrees with the Public Staff that the Commission should adopt the Task Force's recommendation to expand the Lifeline/Link-Up eligibility criteria and direct the affected telephone companies to file appropriate tariffs to reflect this expansion. Accordingly, NCUC Rule R9-6(c)(2) should be rewritten to read as follows:

> (2) In order to be eligible for assistance, a residential subscriber must be a current recipient of Supplemental Security Income, Foods Stamps, Medicaid, Low Income Home Energy Assistance Program (LIHEAP), federal public housing and Section 8 housing assistance, or a current participant in Work First or Temporary Assistance for Needy Families.

The Commission believes that the adoption of the federal public housing criterion would broaden the base of possible recipients of Lifeline/Link-Up benefits, which is the goal of the Commission. According to HUD, there are 39,000 federal public housing units in North Carolina. The Task Force noted that there are many families living in federal public housing who work low wage jobs, which makes them ineligible for Food Stamps and other qualifying benefits. The Commission believes that adding the federal public housing criterion to those currently in place for Lifeline/Link-Up eligibility is a worthwhile and prudent decision. As such, the Commission approves adding occupation of federal public housing to the list of qualifying criteria to receive Lifeline/Link-Up benefits.

The Commission is also of the opinion that the comments of Sprint Nextel are not relevant to the question currently before the Commission, i.e., the expansion of eligibility criteria to include recipients of federal public housing. Furthermore, the Commission believes that the concerns raised by Sprint Nextel, to the extent they are valid and relevant, should be referred to the Lifeline/Link-Up Task Force for its members to address at the appropriate time.

Additionally, now that the Commission has approved the Task Force recommendation to include participation in the federal public housing program in the list of programs rendering one eligible to receive Lifeline/Link-Up assistance, AT&T is to proceed with implementation of the pilot study on the self-certification of eligible participants for Lifeline/Link-Up benefits and to report its findings to the Commission as set out in the Commission's previous Order.

Finally, the Commission notes that the latest Lifeline statistics show a decline in the number of households receiving Lifeline benefits, but the report does not explain the decline. The Commission requests that the Task Force submit a follow-up report explaining the reasons for the decline. Furthermore, in subsequent reports, should the statistics show a further decline, the Task Force should provide comments regarding the reasons for declines in program participation and make recommendations regarding measures that can be undertaken or expanded that would improve penetration rates for eligible subscribers. Even if the statistics in future reports show no decline or an increase in participation, the Task Force should provide comments suggesting means for increased participation based on the initiatives that are being undertaken to improve penetration for eligible subscribers.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of April 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh040908.01

DOCKET NO. T-100, SUB 69

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by Movin' On Movers, Inc. to Amend Rule R2-8.1 Applications for Certificates of Exemption; Transfers; and Notice	)	ORDER AMENDING RULE R2-8.1 AND ALLOWING ADDITIONAL COMMENTS

BY THE COMMISSION: On September 19, 2007, an Order was issued in this docket requesting comments from all Commission-certificated movers of household goods (HHG), the Public Staff – North Carolina Utilities Commission (Public Staff), the Office of the Attorney General (Attorney General), and any other interested parties regarding Movin' on Movers, Inc.'s (the Petitioner or Movin' on Movers) request that the Commission expand Rule R2-8.1(a)(3) to include the following additional requirements for the issuance of a certificate of exemption:

e. That the applicant has a current, valid North Carolina Driver's License;

f. That the applicant (or any of its principals) has not been convicted of, or been incarcerated following a conviction for, a felony crime within ten years prior to filing the application; [and]

g. That the applicant is a United States citizen.

The Order requested that those submitting comments include comments on the following issues as well as any other issues deemed relevant to the Commission's consideration of the Petitioner's proposal:

1. Whether the Commission has the authority, consistent with relevant state and federal statutes and constitutional provisions, to require that an applicant for a certificate of exemption to transport household goods (a) have a valid North Carolina driver's license, (b) not have been convicted of a felony crime within the past ten years, and (c) be a United States citizen? If so, please state the legal basis which provides the Commission with such authority. If not, please state the reason that the Commission lacks such authority.

2. If driver's license, felony criminal record, and citizenship information are required on the application for a certificate of exemption, should some, none, or all of the information be treated as confidential and proprietary? If so, should it be provided in a separate exhibit attached to the application?

3. If driver's license, felony criminal record, and citizenship information are required on the application for a certificate of exemption, should such information also be required on the application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption?

4. If driver's license, felony criminal record, and citizenship information are required on a certificate of exemption application, what documents providing proof of such information should be required to be provided by applicant along with the application?

5. Should a person who has been convicted of, or incarcerated for, a felony crime within the past ten years and who has been rehabilitated and released back into society have the right to have the opportunity to become a certified household goods mover? Further, would some time period less than ten years be more appropriate? Explain your responses.

6. Should the circumstances, type, and severity of a felony criminal record be considered by the Commission in determining whether to grant a certificate of exemption to an applicant? Explain/describe how the circumstances, type, and severity of a felony criminal record may or may not warrant special consideration such that an applicant with a felony criminal record might be granted a certificate of exemption.

7. How would you propose/suggest that the possession by an applicant of certain immigration documents (for example, work eligibility documents, Green Cards, Visas) affect his or her legal right to own and operate an intrastate household goods moving business in North Carolina?

In addition, the Order requested that those submitting comments include the specific language that they recommended be included in the certificate of exemption application(s), application exhibit(s), and in Rule R2-8.1. Initial and reply comments were required to be filed no later than October 19, 2007 and November 8, 2007, respectively. By further Order, those dates were extended to November 8, 2007, and November 26, 2007, respectively.

On November 9, 2007, James E. Dunnagan, d/b/a Dunnagan's Moving & Storage, filed a letter with the Commission requesting that a moratorium be placed on the issuance of any new HHG mover certificates of exemption until the Commission's final decision was issued. By Order dated November 27, 2007, the Commission denied the request for such a moratorium.

On April 25, 2008, the Petitioner made a filing in this docket requesting an update on the status of the docket.

Initial comments were filed with the Commission on or before November 8, 2007, by the Public Staff of the Utilities Commission (hereinafter "Public Staff"), Triangle Residential Options for Substance Abusers, Inc. (hereinafter "TROSA"), and the following sixteen certificated HHG movers: Absolute Moving & Storage, Inc. (hereinafter "Absolute"); A & E Moving and Storage, Inc., d/b/a New Bell Storage (hereinafter "New Bell"); All American Relocation, Inc. (hereinafter "All American"); Cardinal Moving & Storage, Inc. (hereinafter "Cardinal"); De Haven's Transfer & Storage, Inc. (hereinafter "De Haven's Transfer"); James E. Dunnagan, d/b/a Dunnagan's Movers & Storage (hereinafter "Dunnagan's Moving"); Easy Movers, Inc. (hereinafter "Easy Movers"); Fidelity Moving & Storage Co., Inc. (hereinafter

"Fidelity"); Modern Moving & Storage, Inc. (hereinafter "Modern"); Petitioner; Ray Moving & Storage, Inc. (hereinafter "Ray Moving"); Salisbury Moving & Storage (hereinafter "Salisbury"); Security Storage Company, Inc. (hereinafter "Security Storage"); Sells Service, Inc. (hereinafter "Sells"); M. M. Smith Storage Warehouse, Inc. (hereinafter "Smith"); and T & K Moving, Inc., d/b/a Two Men and A Truck of Wilmington (hereinafter "TM&T").

Reply comments were filed on or before November 26, 2007, by the following six certificated HHG movers: Christopher Devon Brown, d/b/a Armorbearor Discount Movers (hereinafter "Armorbearor"); Dunnagan's Moving; I.H. Hill Transfer & Storage, Inc. (hereinafter "Hill"); Kenneth Frederick Lloyd, d/b/a Little Lloyd Moving & Transit (hereinafter "Lloyd"); Petitioner; and TM&T.

SUMMARY OF COMMENTS

1. Whether the Commission has the authority, consistent with relevant state and federal statutes and constitutional provisions, to require that an applicant for a certificate of exemption to transport household goods (a) have a valid North Carolina driver's license, (b) not have been convicted of a felony crime within the past ten years, and (c) be a United States citizen? If so, please state the legal basis that provides the Commission with such authority. If not, please state the reason that the Commission lacks such authority.

Petitioner asserts that the Commission has the statutory authority to make the proposed changes, and that this statutory authority is specifically granted to the Commission in G.S. 62-261(8). The Petitioner reasons that on February 22, 2002, in Docket No. T-100, Sub 49, the Commission issued an Order concluding that it would cease issuing Certificates of Public Convenience and Necessity and, pursuant to G.S. 62-261(8), would issue a certificate of exemption to each motor carrier of household goods authorized to operate in North Carolina instead. Significantly, in that same docket, the Commission concluded that it was important to maintain a certain amount of regulation over the transportation of household goods as a measure of protection for the moving public. To that end, the Commission concluded that G.S. 62-261(8) gives the Commission authority to "attach to such certificate such reasonable terms and conditions as the moving public may require. . . ." See Order dated February 23, 2002 (Docket No. T-100, Sub 49). The Commission then identified several criteria that should be attached as conditions for receipt of a certificate of exemption. There is nothing in G.S. 62-261(8) that prohibits the Commission from imposing additional conditions.

The Petitioner further asserts that, despite the Public Staff's comments, G.S. 62-261(8) does not limit a certificate's terms and conditions to fitness and solvency requirements and compliance with the liability insurance provisions of Chapter 62. To the contrary, G.S. 62-621(8) does not state that the Commission can only attach those terms and conditions that are expressly authorized by Chapter 62. In fact, nothing in G.S. 62-261(8), or any other statute for that matter, requires that additional terms and conditions to protect the moving public be expressly authorized by Chapter 62 of the General Statutes. The Petitioner believes that such an interpretation of the statute would take away the authority given to the Commission in G.S. 62-261(8) to attach those terms and conditions it deems necessary.

The Petitioner clarifies that there is nothing contained in its proposal that prohibits or inhibits the opportunity for a hearing to interested parties. The proposal only amends Rule R2-8.1(a)(3). The hearing requirements are not contained in that rule. The right to a hearing as provided in G.S. 62-261(8), and promulgated under Rule R2-11, is protected. This proposal does not in any way deny the applicant authority to transport household goods without an opportunity for a hearing. Currently, if an applicant is denied a certificate of exemption due to lack of financial solvency (currently a condition to obtain a certificate), he or she has the right to a hearing on that issue. If this proposal is adopted and an applicant is denied a certificate on the basis of a history of felony convictions, he or she would have the right to a hearing on that issue pursuant to G.S. 62-261(8) and Rule R-11.

The Public Staff asserts that the Commission has only those powers granted it by the Legislature.[1] In Docket No. T-100, Sub 49, the Commission, being of the opinion that G.S. 62-261(8) did not give it authority to totally deregulate household goods transportation, looked to this statute for authority to exempt the transportation of household goods from compliance with certain of the provisions of Article 12. Pursuant to G.S. 62-261(8), the Commission found that "the current regulatory environment of household goods transportation is of such a nature that certificates of exemption should be issued to motor carriers of household goods" and that certain terms and conditions should be attached to those certificates "to assure continued and adequate levels of protection to the moving public."[2] These terms and conditions are the fitness and solvency requirements set forth in G.S. 62-262(e)(2) and (3), plus the minimum limits of liability insurance coverage set out in G.S. 62-268 and the cargo insurance coverage requirement set out in G.S. 62-152.2. The Petitioner proposes that the Commission amend the terms and conditions attached to a certificate of exemption for the transportation of household goods to include three additional requirements, none of which is expressly authorized by Chapter 62 of the General Statutes.

According to the Public Staff, the Commission may not have the authority, consistent with statutory and constitutional provisions, to amend Rule R2-8.1(a)(3) as proposed by the Petitioner. Even if the Commission is of the opinion that these requirements are "such reasonable terms and conditions as the public interest may require"[3] under G.S. 62-261(8), it must comply with the provision that "[n]o certificate of exemption shall be denied . . . except after reasonable opportunity for hearing to interested parties."

All American asserts that, if the Commission does not have the authority to make the requested changes, then who does? All American believes that Docket No. T-100, Sub 49 gives the Commission the authority to change the requirements for obtaining a certificate of exemption. All American maintains that the Commission over the years has not taken responsibility for what it says, and that the Commission is one part of government that could be eliminated to save taxpayers' money.

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[1] See *State ex. rel. Utils. Comm'n v. Southern Bell Tel. Co.*, 307 N.C. 541, 299 S.E. 2d 763 (1983).

[2] *Deregulation of Transportation of Household Goods Within North Carolina* - Order Ruling on Household Goods Transportation, Docket No. T-100, Sub 49, pages 15-16, (February 22, 2002).

[3] According to the Public Staff, a valid North Carolina driver's license may not be necessary to protect the public interest, because an applicant for a certificate of exemption may not be an operator of any motor vehicles used in the transportation of household goods. The necessity of requiring that an applicant not have been convicted of a felony within the past ten years and be a United States citizen is also unclear.

Cardinal asserts that the Commission has the authority to make the Petitioner's proposed changes. In support of this, Cardinal advanced the following reasoning: In Docket No. T-100, Sub 49, the Commission concluded that it would cease issuing Certificates of Public Convenience and Necessity to HHG movers and instead, pursuant to G.S. 62-261(8), issue certificates of exemption. The Commission deemed that it was important to maintain a certain amount of regulatory control over the transportation of HHG as a measure of protection to the moving public. The Commission concluded that G.S. 62-261(8) gave it the authority to attach to certificates of exemption such reasonable terms and conditions as the public interest required. The current terms and conditions are enunciated by the Commission in Rule R2-8.1. Cardinal opines that the additional conditions requested by the Commission are consistent with relevant state and federal statutes and constitutional provisions.

De Haven's Transfer believes that the Petitioner's proposed changes are within the jurisdiction of the Commission. De Haven's Transfer questions whether the Commission could be held responsible if a registered mover commits a serious crime in the home of a North Carolina resident.

Dunnagan's Moving contends that the Petitioner's proposed changes are not unreasonable and that they are necessary in the interest of public safety. Dunnagan's Moving further contends that the Commission is required by law to provide fair regulation of public utilities in the interest of the public, and to promote adequate, reliable, and economical utility service. Dunnagan's Moving reasons that the Commission can make or adjust rules in the interest of the public.

Fidelity states that certificates of exemption are issued by the Commission. Thus, it is apparent that the Commission believes that some amount of regulation is needed in connection with the transportation of HHG to protect the moving public. Therefore, Fidelity maintains that the Commission should have the authority to make the Petitioner's proposed changes.

Hill observes that it is the Commission's responsibility to maintain the quality of the moving industry since the Commission is the "sole filter for the establishment of moving companies and their owners in" North Carolina. According to Hill, "[t]he mandate of the North Carolina Utilities Commission is to ensure fair trade and consumer protection in" North Carolina. Hill complains that the industry has been damaged by "rogue movers" and alleges that the moving public wants higher standards that only the Commission can provide.

Modern supports the Petitioner's proposed changes. Modern believes that an applicant should meet certain requirements before the Commission grants it a certificate of exemption. Modern reasons that, since the Commission has the authority to issue certificates of exemption, it should also have the authority to make changes to Rule R2-8.1 to the extent necessary.

Ray Moving expresses hope that the Commission is as concerned for the consumer as it is with the legalities of the matter. Ray Moving acknowledges the legal difficulties of the matter, but also contends that the Commission has an obligation to protect the consumer by requiring people who are hired to enter someone's home and move his belongings to satisfy appropriate criteria. Ray Moving states that it hopes the Commission appreciates the Petitioner's concern about the consequences of letting just anybody have access to consumers' belongings.

Salisbury opines that the Commission should have the authority to require an applicant to meet these important requirements.

Sells contends that the Commission has the authority to issue certificates of exemption to movers and to "attach to such certificate reasonable terms and conditions as the public may require" as is stated in G.S. 62-261(8), which is the basis for the Petitioner's proposed changes. Sells further maintains that the Commission has established the current criteria for obtaining a certificate of exemption, so it stands to reason that the Commission has the authority to change these criteria. Sells is of the opinion that the Petitioner's proposed changes do nothing to inhibit the ability of any reasonable applicant to obtain a certificate of exemption. Further, Sells opines that the moving public expects any mover that is hired to be in this country legally, have a valid North Carolina driver's license, and have a criminal record free from convictions for serious charges, just as they expect the mover to have basic insurance coverage. Sells comments that a certificate of exemption granted to a mover by the Commission does not offer the consumer any warranty or guarantees, but it does indicate to the consumer that the mover is legitimate. Sells alleges that consumers would be dismayed to know that a mover, although operating legally, is owned by someone who is in this country illegally, does not have a driver's license, or has been convicted of a violent crime and that these factors were not even considered by the Commission in granting the mover its certificate of exemption.

Smith states that the Commission has been granted the authority pursuant to G.S. 62-261(8) to promulgate rules to protect the moving public, and, therefore, has the authority to require an applicant for a certificate of exemption to satisfy requirements that are in the public interest.

Security Storage asserts that the Commission has the authority to make the Petitioner's proposed changes and to attach to a certificate of exemption such reasonable terms and conditions as the public interest may require.

TM&T opines that the Commission has been charged with the responsibility of certifying that an individual is fit, willing, and able to serve the moving public that, and if the Commission is going to do this, it should make sure that it has the authority to perform its job.

TROSA opposes the Petitioner's proposed changes. TROSA states that there is already a process in place for the moving industry in North Carolina to be heard concerning applications for the issuance of a certificate of exemption. TROSA comments that, under the current process, other moving companies have the right to comment and voice their disapproval of any applicant and that, in this manner, the industry can decide on a case-by-case basis whether an applicant is a suitable candidate for the issuance of a certificate of exemption. TROSA acknowledges that there are instances under the current process in which unsuitable applicants have been granted certificates of exemption. However, TROSA contends that it is not clear that the proposed changes would accomplish the desired result of effectively screening out problem applicants.

1. (a) Whether there are any statutory or constitutional challenges to the requirement for North Carolina driver's license?

The Petitioner believes that a valid CDL license is necessary to ensure that the operator is knowledgeable about operating a commercial vehicle. The Petitioner contends that requiring an applicant to have a valid driver's license is an obvious and reasonable condition to place on the certificate of exemption. The Petitioner contends that the proposed requirement that an applicant for a certificate of exemption have a valid driver's license is necessary to protect the moving public by ensuring that an authorized HHG mover has the legal right to operate the vehicles necessary for making HHG moves. The Petitioner explains that the large majority of HHG moves are conducted with commercial vehicles and that operators of these vehicles are required to have a valid CDL license.

The Public Staff made no direct comments regarding this proposed requirement.

Absolute questions how a requirement that a person having a valid driver's license would "protect the moving and consuming public and the integrity of the moving industry." In that regard, Absolute asks (1) if a person is physically disabled, cannot drive, or simply chooses not to have a driver's license, why that fact should that prohibit such person from owning a moving company, and (2) why should having a valid driver's license be a prerequisite for owning this type of business?

Cardinal believes that a valid North Carolina driver's license is already required in order to operate a motor vehicle in North Carolina. The Commission has the authority to confirm that HHG movers are authorized to operate the vehicles used in HHG moves.

Easy Movers asserts that applicants should possess a valid driver's license to be able to move personal property.

Hill indicates that a North Carolina driver's license is already necessary for residents of our state, and the Commission is not placing undue weight on anyone by requiring compliance with such a requirement.

New Bell opposes the requirement that an applicant have a North Carolina driver's license. New Bell contends that a business owner does not need, nor is it required that a business owner have, a driver's license in order to own or operate a HHG moving company. Mr. Ashley, New Bell's owner, states that he does not drive a truck, nor has he ever driven one. New Bell further states that, under federal commercial license requirements, drivers are not required to maintain a license issued by the state in which they are domiciled. New Bell explains that drivers are only required to have one license. New Bell contends that requiring an applicant to have a North Carolina driver's license before obtaining the issuance of a certificate is a restraint of trade rather than a deterrent to poor service. Furthermore, New Bell opines that requiring an applicant to have a valid North Carolina driver's license does not protect the moving and consuming public.

Ray Moving does not understand why there would be any challenge to the driver's license requirement, considering that a driver's license is required to facilitate the transportation of someone's belongings and that such a driver's license requirement increases the chances that a truck and its contents are insured in the event of an accident.

TROSA contends that it is not clear why requiring an applicant for a certificate of exemption to have a current and valid North Carolina driver's license would be a relevant criterion for someone to operate a business in North Carolina. TROSA explains that an applicant may not be a resident of North Carolina and, therefore, not be eligible for a North Carolina driver's license. TROSA further explains that an applicant may not have a driver's license simply because he does not drive. TROSA contends that whether an applicant has a driver's license has no bearing on his ability to effectively run a reputable moving company since owners of moving companies need not, and in most cases do not, operate the moving vehicles. TROSA further contends that it is clear, however, that anybody that operates moving vehicles must have a valid driver's license.

1. (b) Whether there would be a statutory or constitutional challenge to the criminal record requirement?

The Petitioner comments that, currently, an applicant for a certificate of exemption is not required to provide any criminal background information. Further, the Petitioner remarks that it is not aware that the Commission conducts any criminal background checks on applicants. Therefore, the Petitioner concludes that there currently is no process in place to protect the moving public from misconduct by convicted felons. The Petitioner observes that a felony is a serious crime; felonies typically involve conduct that violates either person (e.g., rape, assault, death) or property (e.g., burglary or other stolen property) or involvement with illegal drugs. The protection of the moving public from persons that have engaged in such activities should be a high priority. The Petitioner asserts that at least three other states -- Illinois, Washington, and California – have rules that allow their administrative agencies to refuse a moving permit to an applicant who has a criminal background. In Illinois, the justification for refusal is not just limited to crimes resulting in felony convictions, but also includes "crimes involving dishonesty or false statement regardless of the punishment." In Washington, the administrative agency considers whether the applicant has violated "any state law," not just whether the applicant has been convicted of a felony. In California, the administrative agency can refuse a permit to an applicant who has "committed any act or dishonesty or fraud" or "committed a felony or crime or moral turpitude." Significantly, in each of these states, there are no time limitations on when the crime or conviction may have occurred. There is also no specific consideration of whether the applicant may have been rehabilitated. The Petitioner comments that other North Carolina administrative agencies have promulgated rules to protect the public from misconduct by convicted felons. The Petitioner points to G.S. 87-10 which provides the North Carolina Licensing Board for General Contractors with the authority to deny a general contractor's license to an applicant who has been convicted of a felony involving moral turpitude or misappropriation of property. Similarly, G.S. 74F and 21 NCAC Ch.29, Section.0402 provides that locksmith applicants convicted of a Class A or Class B felony are permanently ineligible for licensure. These rules also state that an applicant who has been convicted of a Class C, D, E, or F felony should not be granted a license unless more than 12 years have elapsed since the completion of the applicant's sentence. The Petitioner remarks that it was not aware of any statutory or constitutional challenges to said rules.

The Public Staff states that it is not aware of any state in which the authority to transport household goods is automatically denied on the basis of criminal history or lack or United States citizenship without an opportunity for a hearing. The Public Staff asserts that the United States Supreme Court has recognized the severity of depriving a person of the means of earning a livelihood[1] and states that "[i]t requires no argument to show that the right to work for a living in the common occupations of the community is of the very essence of the personal freedom and opportunity that it was the purpose of the [Fourteenth] Amendment to secure."[2] The right to hold specific private employment and to follow a chosen profession free from unreasonable governmental interference comes within both the "liberty" and "property" concepts of the Fifth and Fourteenth Amendments.[3] Further, the Public Staff asserts that the Supreme Court has consistently interpreted the Fifth and Fourteenth Amendments to apply to all people present in the United States, regardless of their status under the immigration laws.[4]

Absolute wonders how the addition of the Petitioner's proposed changes would protect the community served by common carriers of HHG by preventing ownership of a moving business by a felon. In that regard, Absolute asks what would a drug possession, conviction, and time served at 18 years of age have to do with the ability of a person who now 25 years old and has been a productive member of society for seven years to start and successfully operate his own moving company?

Hill supports the Petitioner's proposed felony rule, that is, the rule that states that an applicant for a certificate of exemption (or any of its principals) must not have been convicted of, or been incarcerated following a conviction for, a felony crime within 10 years prior to filing the application. Hill believes that the proposed felony rule provides the security the moving industry in North Carolina needs. Hill does not believe, however, that the rule disqualifies, from gainful employment in North Carolina, those convicted felons who would not be able to obtain a certificate of exemption because of the rule. Hill maintains that the rule should be considered only as a delay in or postponement of the opportunity for a convicted felon to obtain a certificate of exemption. Hill further maintains that a convicted felon can work for any North Carolina moving company that will hire him in the interim. Therefore, Hill states that the felony rule limits the ownership of a business, and not the employment of an individual.

Ray Moving argues that a felony conviction is a very serious matter and should not be looked upon lightly. Ray Moving asks "[i]f a convicted felon does not have rights of law abiding citizens, would the Commission want this person moving its belongings or its constituent's belongings?"

TM&T disagrees with the Public Staff's analysis that there is a right to work issue involved in this matter. TM&T maintains that the right to work has nothing to do with the right

[1] Cleveland Bd. of Education v. Loudermill, 470 U.S. 532, 543 (1985).
[2] Truax v. Raidch, 239 U.S. 33, 41 (1915).
[3] Greene v. McElroy, 360 U.S. 474, 492 (1959).
[4] See Plyer v. Doe, 457 U.S. 202, 210 (1982).

to be granted a certificate of exemption to own and operate a moving company. TM&T explains that the right to work would be at issue if, for example, the authorized company refused to hire somebody because of his background. TM&T further explains that, when the Commission grants a certificate of exemption to a mover, the right to work is not at issue. Instead, the Commission is "certifying to the general public that the person holding the certificate is fit, willing, and able to come into the public's homes and move household goods." TM&T asserts that the Petitioner's proposed changes are intended to protect the moving public and the integrity of the industry and not to deny persons the right to work or to limit competition. TM&T states that the current application approval process is giving the moving public a false sense of security and that it is "border line negligence."

1. (c) Whether the requirement of United States citizenship will have any statutory or constitution challenges?

The Petitioner observes that currently there is no requirement that an applicant for a certificate of exemption show any documentation indicating lawful presence in this country. It is the opinion of the Petitioner that it is important to the moving public that a HHG mover be lawfully in the United States; that holding a certificate of exemption is not a right, but a privilege; and that this privilege should only be granted to persons who are lawfully in this country. The Petitioner argues that illegal aliens are not subject to the state and federal laws (e.g., workers' compensation, employment, and tax laws) that protect the public interest.

The Public Staff is not aware of any state in which authority to transport household goods is automatically denied on the basis of a criminal history or lack or United States citizenship without an opportunity for a hearing. The Public Staff asserts that the United States Supreme Court has recognized the severity of depriving a person of the means of a livelihood[1] and states that "[i]t requires no argument to show that the right to work for a living in the common occupations of the community is of the very essence of the personal freedom and opportunity that it was the purpose of the [Fourteenth] Amendment to secure."[2] The right to hold specific private employment and to follow a chosen profession free from unreasonable governmental interference comes within both the "liberty" and "property" concepts of the Fifth and Fourteenth Amendments.[3] Further, the Supreme Court has consistently interpreted the Fifth and Fourteenth Amendments to apply to all people present in the United States, regardless of their status under the immigration laws.[4]

Fidelity contends that a mover must be a United States citizen to give the moving public reliable service. Fidelity explains that a mover in the United States on a Visa could have the Visa revoked, resulting in a customer's goods being stranded in the mover's warehouse or truck(s).

Ray Moving believes requiring a certificate of exemption applicant to be a United States citizen is more than reasonable. Ray Moving states that "[O]ur whole system, local, state, and

[1] Loudermill, 470 U.S. at 543.
[2] Raidch, 239 U.S. at 41.
[3] McElroy, 360 U.S. at 492.
[4] Doe, 457 U.S. at 210.

nationally is affected by illegal aliens. It goes without saying that this is obviously a reasonable request."

Salisbury believes that it is very important that a mover be a United States citizen to ensure that state and federal tax laws, immigration laws, employment laws, and workers' compensation laws and requirements are followed.

TM&T contends that an applicant for a certificate of exemption should be either a United States citizen or a "legally naturalized immigrant." TM&T argues that, if an applicant cannot follow this country's immigration laws, then it is safe to assume that he will not follow any other requirements placed on him by North Carolina.

TROSA contends that it is not clear why it should be a requirement that an applicant for a certificate of exemption should be a United States citizen. TROSA argues that, while it is opposed to an applicant who is in this country illegally being granted a certificate of exemption, there might be cases where somebody is in this country legally and is eligible to operate a business in North Carolina or anywhere else in the United States. Applicants in that position should not be denied a certificate of exemption. TROSA further states that "[c]hecking to see that someone can own and operate a business makes sense, but the rule as proposed would wrongly exclude certain people."

2. If driver's license, felony criminal record, and citizenship information are required on the application for a certificate of exemption, should some, none, or all of the information be treated as confidential and proprietary? If so, should it be provided in a separate exhibit attached to the application?

The Petitioner states that the driver's license, felony criminal record, and citizenship information should be treated as confidential.

The Public Staff comments that all of the required driver's license, felony criminal record, and citizenship information should be attached to the application as a separate exhibit and marked confidential.

Absolute asserts that, in the event that driver's license, felony criminal record, and citizenship information are required to be submitted with the application for a certificate of exemption, the information should not be treated as confidential and proprietary.

All American remarks that it sees no problem with the Commission's keeping driver's license, criminal record, and citizenship information confidential even though none of that information is currently protected as confidential under the law.

Cardinal maintains that it would be appropriate and reasonable for the Commission to treat driver's license, criminal record, and citizenship information as confidential; however, none of this information is currently protected as confidential information under the law. Cardinal notes that all this information can be easily accessed through the Internet by anyone.

Fidelity believes that, due to the confidentiality of driver's license, criminal record, and citizenship information, "[a]ll the information that is public does not need to be on a separate exhibit. The Commission could require non-public information on a separate exhibit."

Modern comments that driver's license, felony criminal record, and citizenship information is all public information, and, therefore, need not be treated as confidential or proprietary by the Commission. However, Modern further comments that any information from an applicant that is not public information should be provided on a separate exhibit attached to the application.

Salisbury states that putting driver's license, criminal record, and citizenship information in a separate exhibit to the application might be a way to protect the confidentiality of that information if the Commission should choose to protect such information.

Security Storage states that the confidentiality of driver's license, criminal record, and citizenship information should be confidential if required by law.

Sells believes that driver's license, criminal record, and citizenship information should not be treated as confidential by the Commission so that other certificate holders can view it and determine whether a protest is warranted.

Smith contends that driver's license, felony criminal record, and citizenship information is not currently protected as confidential under the law. Smith states that most movers obtain such information from various Internet databases when they hire new employees and review current employees. Smith sees no need to restrict the availability of such information since it is readily available.

3. **If driver's license, felony criminal record, and citizenship information are required on the application for a certificate of exemption, should such information also be required on the application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption?**

The Petitioner recommends that both (1) the application for a certificate of exemption and (2) an application to sell, assign, pledge, etc., a certificate of exemption should be handled alike, i.e., if the holder sells a certificate of exemption, the same rules applicable to new applications should apply.

The Public Staff comments that the same information that is required to be provided in connection with an application for the issuance of a new certificate of exemption should also be required on an application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate.

Absolute asserts in its comments that driver's license, felony criminal record, and citizenship information should not be required to be submitted with an application to sell, assign, pledge, etc., a certificate of exemption.

All American states that, even though the certificate of exemption has no value, driver's license, criminal record, and citizenship information should be required in connection with an application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption.

Cardinal states that it would be appropriate to require driver's license, criminal record, and citizenship information to be included on an application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption.

De Haven's Transfer recommends that the Petitioner's proposed changes should apply to all applicants for a certificate of exemption, including those applicants using the application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption. Otherwise, De Haven's Transfer argues, an unqualified mover could obtain a certificate of exemption by simply buying an existing certified moving company.

Fidelity asserts that the same information required on applications for a new certificate of exemption should be required on all applications to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption. Fidelity believes this will protect the moving public.

Modern states that any driver's license, felony criminal record, and citizenship information the Commission requires from an applicant for issuance of a certificate of exemption should also be required in connection with an application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption. Modern also believes that a new owner of a moving company should have to reapply for a certificate of exemption.

Salisbury believes that the Petitioner's proposed changes should apply to all applicants for a certificate of exemption, including those applicants using the application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption.

Security Storage believes that an application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption should include the same information required of applicants for the issuance of a new certificate since it is needed to ensure that the moving public is protected.

Sells states that the Petitioner's proposed changes must apply to all applicants for a certificate of exemption, including those applicants using the application to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption.

Smith remarks that it is the Commission's responsibility to protect the moving public and to ensure that certificated movers are responsible, law abiding citizens. Accordingly, Smith comments, the Commission should handle applications to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption in the same manner in which it handles applications for new authority. Specifically, Smith recommends that a new subsection be added to Rule R2-8.1 (b), concerning applications to sell, assign, pledge, transfer, lease, merge, or acquire control of a certificate of exemption, requiring that applicants comply with these new requirements.

4. **If driver's license, felony criminal record, and citizenship information are required on a certificate of exemption application, what documents providing proof of such information should be required to be provided by applicant along with the application?**

The Petitioner believes that copies of (1) a NC driver's license; (2) a criminal record check (available from www.NC123.com); and (3) a birth certificate and/or citizenship papers that prove US citizenship should be required to be provided to the Commission by an applicant.

The Public Staff asserts that the required information should consist of a copy of (1) a valid regular driver's license or commercial driver's license issued by the Department of Motor Vehicles (hereinafter "DMV"), or a driver's license issued by another state that is recognized by the DMV as valid for operation on North Carolina highways; (2) a criminal history record check performed by the State Bureau of Investigation; and (3) either a birth certificate, United States passport, certificate of United States citizenship, or certificate of naturalization.

Absolute suggests that, if the information in question is required to be provided, then a copy of driver's license, criminal background check, and employment eligibility verification from the Department of Homeland Security should be provided and that, other than the copy of the driver's license, the forms of verification should be developed by the Commission, which should incur all verification-related costs.

All American asserts that an applicant should provide a copy of his North Carolina driver's license; a copy of his criminal record, which can be obtained from an authorized agency; and a copy of his birth certificate or other documents sufficient to prove United States citizenship status.

Cardinal asserts that a HHG mover applicant should provide to the Commission a copy of its North Carolina driver's license and a printout from the DMV which shows that the applicant's license is currently valid; a certified copy of his criminal record from an authorized agency such as www.NC123.com; and a copy of his birth certificate or certified citizenship documents sufficient to prove his status as a United States citizen.

De Haven's Transfer suggests that the Commission consider using the Employment Eligibility Verification I-9 Form, which is required of employers for their employees. De Haven's Transfer explained that this form does not mandate United States citizenship, but that it provides a good and fair means of establishing identity and employment eligibility.

Dunnagan's Moving suggests that background checks could easily be performed through public records or the Internet, and it proposed that financial background records be submitted with the application, along with verified proof of the applicant's statement.

Fidelity recommends that the Commission require that an applicant for a certificate of exemption submit a copy of his North Carolina driver's license, a document from the North Carolina DMV verifying the validity of the driver's license, and documents proving United States citizenship.

Modern asserts that the driver's license, felony criminal record, and citizenship information an applicant provides to the Commission should consist of a copy of a North Carolina driver's license, DMV motor vehicle report, national criminal background check report, and proof of United States citizenship.

Salisbury remarks that an applicant for a certificate of exemption should provide a copy of his North Carolina driver's license, proof from the DMV that the license is valid, a copy of his birth certificate or certified citizenship documents proving United States citizenship, and a certified copy of any criminal record.

Security Storage recommends that an applicant for a certificate of exemption be required to submit (1) a copy of its North Carolina driver's license, (2) a document from the North Carolina DMV verifying the validity of the driver's license, (3) a certified copy of his criminal record from an authorized agency, and (4) either a certified copy of his birth certificate or citizenship documents proving United States citizenship. Further, Security Storage warns that the accuracy and reliability of information from outside the United States may be questionable.

Sells recommends that a valid North Carolina driver's license, a copy of a criminal record check, and a birth certificate should serve as documentation to verify compliance with the Petitioner's proposed changes. However, Sells added that it will be absolutely necessary for the Commission to verify the validity of such documents.

Smith provides the following comments concerning the types of documents an applicant for a certificate of exemption should provide along with its application. For the proposed driver's license requirement, Smith suggests that an applicant provide a photocopy of its current driver's license along with a DMV printout proving that the license is current. Smith added that, if the applicant is from out of state, then the same information from that state could be provided. For the proposed criminal record requirement, Smith suggests that an applicant provide a certified copy of his criminal record from a recognized criminal records provider who conducts nationwide checks. Smith adds that it is insufficient to obtain a certified copy of a criminal record from just a local police or county ID Bureau check. For the proposed citizenship requirement, Smith recommends that an applicant provide a copy of his birth certificate or certified naturalization papers proving United States citizenship status. Smith contends that Green Cards should not be accepted.

5. Should a person who has been convicted of, or incarcerated for, a felony crime within the past ten years and who has been rehabilitated and released back into society have the right to have the opportunity to become a certified household goods mover? Further, would some time period less than ten years be more appropriate? Explain your responses.

The Petitioner's opinion is that all types of felonies should be treated the same and that 10 years is an appropriate amount of time to restrict a person from becoming a certified HHG mover. The Petitioner queried whether a Commissioner would want to let any of these felons, such as child molester, embezzler, rapist, or murderer into his or her home or want to be responsible for allowing them into the unsuspecting public's home? The Petitioner noted that 74% of all felons return to prison within 10 years of their release and that, after 10 years, the recidivism rate drops significantly. The Petitioner observed that a felony conviction results in the revocation of a felon's rights to vote and to hold a government job. It is the Petitioner's position that if the United States Constitution is amended so as to change these rules, then the Commission should reopen this proceeding.

The Public Staff asserts that a person who has been convicted of, or incarcerated for, a felony offense within the past ten years who has been rehabilitated, released back into society, and has had his or her rights restored under G.S. 13-1 should have the opportunity to become a certified household goods carrier.

Absolute believes that a person who has been convicted of, or incarcerated for a felony crime within the past 10 years and then rehabilitated and released back into society should have the opportunity to become a certificated HHG mover. Absolute observes that the law states that a person who commits a crime and pays for that crime with incarceration owes nothing in the way of compensation or debt to society. Furthermore, Absolute comments that the type of crime should be relevant. Absolute asserts that it is important to protect consumers/customers from potential violent offenders (those who commit crimes such as rape, murder, pedophiles, or sex crimes). However, Absolute also states that a person with a felony DUI conviction two years ago who turns his life around should not be denied the opportunity to better himself. Absolute queries who determines where the line is drawn? On a personal note, the owner of Absolute, Mr. Duckworth, states that he has had a rough past and that's exactly what it is – the past. He states that he is thankful for the privilege to have his own company and the honor to give back to his community.

Armorbearer asserts that "Felon" is a term applied to people who have committed certain crimes. Felonies can range from financial crimes, drugs, or murder. All crimes should be viewed as serious matters, whether they are misdemeanors or felonies. Once a person has served his sentence, most of his rights are restored. Why continue to punish him by not allowing him to obtain a certificate of exemption?

Cardinal comments that a felony is a serious crime that usually involves the type of conduct that violates a person's body (i.e., rape, assault, death) or property (e.g., burglary) or involves possession of or trafficking in drugs. Cardinal asserts that the moving public requires protection from persons associated with such activities. Cardinal questions whether a convicted felon should be at some point, granted the opportunity to move a family's HHG. In considering this question, Cardinal observes that some felons succeed after incarceration and counseling that convicted felons should be given opportunities to make a living, and that studies show that it often takes about 10 years to determine whether a convicted felon has been fully rehabilitated. It is Cardinal's position that, given these considerations, and the level of direct contact movers have with customers and their belongings, 10 years is a reasonable amount of time to assure that a convicted felon will not commit a horrific crime involving the moving public. In regard to a felon's rights and privileges, Cardinal states that convicted felons currently are not allowed to vote and are stripped of certain privileges available to other citizens. Rehabilitation and time limitations are not considered. Holding a certificate of exemption to move household goods is not a 'right,' it is a privilege granted to persons who satisfy certain requirements. The State of North Carolina (through the DMV) has the right to permanently revoke a person's driver's license (the 'privilege to operate a vehicle') for violating various laws. There is nothing different here.

De Haven's Transfer believes that shortening the proposed 10-year period would increase the risk to the public. De Haven's Transfer also believes that rehabilitated criminals should have gainful employment. However, De Haven's Transfer argues that the moving industry, by its very nature, places employees in close proximity to and in private quarters with women, children, and valuables, all of which can tempt possible repeat offenders. Given the nature of the HHG moving industry, De Haven's Transfer expresses concern about not just felony convictions, but also recent, multiple misdemeanor charges. De Haven's Transfer also suggests that it should be clarified in this rulemaking whether the 10-year period begins at conviction or completion of the sentence.

Easy Movers supports the Petitioner's proposed changes. Easy Movers states that it does not hire employees with recent felony convictions and it asked that the Commission not grant certificates of exemption to applicants with recent felony convictions. Easy Movers also remarks that persons with felony convictions have exhibited traits of irresponsibility and a lack of respect for the law and such persons cannot obtain a valid driver's license or be hired by the federal government. Easy Movers believes "that we should not subject customers to conditions that we would not want to subject our families or our government establishment to."

Fidelity opines that "[t]he moving public should be protected from people convicted of a felony crime. After 10 years back in good standing within the society a person should be able to apply for . . . [a certificate of exemption]." Fidelity adds that it is unnecessary for the Commission to consider the circumstances, type, and severity of a felony criminal record in determining whether to grant a certificate of exemption to an applicant.

Modern opines that a person who has been convicted of, or incarcerated for, a felony should not be allowed to apply for a certificate of exemption until he has been rehabilitated and has been back in society in good standing for at least 10 years. Furthermore, Modern believes that, since all felonies are significant crimes, the Commission should treat all felonies alike.

Salisbury supports the Petitioner's proposed changes. Salisbury believes that granting certificates of exemption to only applicants that have not been convicted of, or incarcerated for, a felony crime within a 10-year period would reduce theft from customers. Salisbury asserts that a period of less than 10 years would not be appropriate and could possibly put customers in danger. Salisbury maintains that members of the general public have the right to be able to assume that their families and possessions will be safe when they let a mover into their home.

Security Storage is of the opinion that 10 years is the minimum time in which a convicted felon should be denied the opportunity to become a certified HHG mover. Further, Security Storage opines that a convicted felon should be denied the opportunity to become a certified HHG mover even beyond 10 years if the Commission believes that the applicant may in any way be a risk to the moving public. Security Storage adds that the Commission may not want to put itself in the position of considering the circumstances, type, and severity of a felony criminal record in determining whether to grant a certificate of exemption to an applicant.

Sells asserts that a convicted felon should prove that he has been rehabilitated before being granted a certificate of exemption. Accordingly, Sells believes that a convicted felon should not be eligible for a certificate of exemption until 10 years after incarceration has ended. Sells states that "[a] felony crime is a felony crime." Sells is most concerned though about violent crimes, drug crimes, crimes against children, and crimes of a sexual nature. Sells contends that exposing unsuspecting consumers to convicted felons who committed such crimes is irresponsible, and that to do so with the blessing of the Commission is unthinkable.

TM&T supports some sort of restrictions on the granting of certificates of exemption to convicted felons. TM&T suggests that the time period for which a convicted felon should be denied the opportunity to receive a certificate of exemption ought to vary depending on the type of crime involved. TM&T further suggests that ten years might be too long for some types of crimes, and that some types of crimes might not be considered serious enough to justify denying an applicant a certificate of exemption.

TROSA comments that, while it is true that felony conviction implies the commission of a serious crime, there are some important things that need to be kept in perspective. First, a felony conviction should not automatically be treated as an indictment of a person's honesty or their ability to operate a professional, reputable business. Second, this proposed rule selects an arbitrary time-frame for determining rehabilitation. TROSA has a strong belief that people can change, that applicants should be dealt with on a case-by-case basis, and that no artificial line in the sand should be drawn.

6. Should the circumstances, type, and severity of a felony criminal record be considered by the Commission in determining whether to grant a certificate of exemption to an applicant? Explain/describe how the circumstances, type, and severity of a felony criminal record may or may not warrant special consideration such that an applicant with a felony criminal record might be granted a certificate of exemption.

The Petitioner's opinion is that all types of felonies should be treated the same by the Commission and that 10 years is an appropriate amount of time to restrict a person convicted of committing a felony from becoming a certified HHG mover.

The Public Staff opines that the Commission should consider the circumstances, type, and severity of an applicant's felony criminal record in determining whether to grant a certificate of exemption. The Public Staff further opines that the Commission should scrutinize criminal history record checks that reveal one or more of the felony criminal offenses set forth in Chapters 14, 20, and 90. The Public Staff recommends that the Commission consider, among other things, the date of the crime, the age of applicant, the circumstances surrounding the commission of the crime, any evidence of rehabilitation, the duties and responsibilities related to the activities conducted by an HHG carrier, and the public policy considerations relating to an ex-offender's right to work in determining whether a certificate of exemption should be granted or denied based upon information contained in an applicant's criminal history record check.

All American contends that a felony is a serious crime that includes violent offenses such as rape, assault, and murder and nonviolent offenses such as theft and possession of and trafficking in drugs. All American further comments that protecting the moving public from people that perpetrate felony crimes is, or should be, a high priority for the Commission. All American believes that a convicted felon should never be allowed to move a family's household goods. All American notes that convicted felons cannot vote and are stripped of other privileges and that rehabilitation and time limitations are relevant to these disabilities. It is the opinion of All American that holding a certificate of exemption is not a right, but is instead a privilege granted to persons who satisfy certain requirements. All American questions whether anyone in the Commission would expose his or her family or possessions to possible misconduct by a convicted felon by virtue of allowing such persons access to individual homes during the moving process. All American asserts that a felony is a felony under the law and that the Commission should treat all of them alike.

Cardinal believes that the Commission should consider the circumstances, type, and severity of an applicant's criminal record in determining whether to grant a certificate. Cardinal observes that neither Illinois nor Washington limit the criminal conduct considered in the application process to felonies. In Illinois, the Commission can consider the type of crime, when the crime occurred, and the age of the applicant at the time of the incident. In Washington, the Commission does not consider these factors. Cardinal argues that, while it may be appropriate to consider the characteristics of a crime if one is looking at both misdemeanors and felonies, it is not appropriate when the scope of inquiry is limited to felony convictions or incarcerations following felony convictions since felonies are so serious. Cardinal asserts that the Commission should not consider the characteristics of a felony criminal record and should treat all such criminal records alike.

De Haven's Transfer comments that, if the Commission were to consider the characteristics of a criminal record, it might need to establish a fair matrix for justifying granting certificates to some felons and not others and that such an undertaking might be quite complex. De Haven's Transfer further comments that, if such a matrix were to be established it might possibly include misdemeanors as well as felony crimes. De Haven's Transfer favors a simple 10-year felony rule to keep the North Carolina moving business safe for the public.

New Bell remarks that, if criminal records are to be considered in the application process, the type of felony should be considered in the decision of whether to grant a certificate to an applicant. New Bell opines that everyone is entitled to a chance at rehabilitation and that some convicted felons will become good citizens.

Salisbury contends that the circumstances, type, and severity of a felony criminal record should be considered by the Commission in determining whether to grant a certificate of exemption to an applicant. For example, Salisbury argues that if an applicant's crime is of an extremely serious nature, it might be in the best interest of consumers for the applicant to never be granted a certificate. Further, Salisbury remarks that, when a mover moves a family, it only takes one horrible incident for that family to lose it all. Therefore, very careful consideration should be given by the Commission before granting authority to an applicant.

Smith contends that the circumstances, type, and severity of a felony criminal record should not be considered by the Commission in determining whether to grant a certificate of exemption to an applicant. In support of its position, Smith states that the United States Government does not consider degrees of a felony and neither should the Commission. In addition, Smith observes that the States of Washington and Illinois have requirements similar to those applied by the United States Government, which are much broader than the Petitioner's proposed requirements. Smith asserts that "[t]he Commission should not have to act as judge and jury in this matter (severity), a felony does not warrant special consideration."

TROSA comments that while it is true that a felony conviction implies the commission of a serious crime, there are some important things that need to be kept in perspective. First, a felony conviction should not automatically constitute an indictment of a person's honesty or his ability to operate a professional, reputable business. Second, the proposed rule selects an arbitrary time-frame on rehabilitation. TROSA has a strong belief that people can change. It is TROSA's opinion that the issues sought to be addressed by the proposal relating to applicants' criminal records should be dealt with on a case-by-case basis, and that no artificial line in the sand should be drawn.

7. How would you propose/suggest that the possession by an applicant of certain immigration documents (for example, work eligibility documents, Green Cards, Visas) affects his or her legal right to own and operate an intrastate household goods moving business in North Carolina?

The Petitioner argues that anybody who is an illegal alien should not have the right to own and operate a HHG moving company. The Petitioner asks what gives an illegal immigrant any legal rights?

The Public Staff contends that an applicant's possession of immigration documents evidencing employment authorization regardless of citizenship status should be sufficient to permit an applicant to own and operate an intrastate household goods moving business in North Carolina.

Absolute contends that the Commission should follow federal guidelines for any questions about citizenship or questions about owning a business, assuming that the applicant is not a United States citizen. Absolute remarks that both the federal government and the State of North Carolina already recognize that a person who has certain documentation can work.

All American remarks that immigration documents should not be considered by the Commission and that if a person is not a United States citizen should not be able to own and operate a HHG moving business or any other business in this state or country. All American questions what gives a non-tax paying illegal any rights or privileges in this country, and also why the Commission would want to allow an illegal immigrant the same business opportunities as a United States citizen?

Cardinal argues that it is important that a mover be a United States citizen and gives two reasons in support of this argument: The first is that the moving public is best served and protected by movers that comply with all state and federal tax, immigration, employment, workers' compensation, and other laws. The second reason is that the moving public needs the reliability that only a United States citizen can provide. Cardinal remarks that immigrants, even those with immigration documents, tend to be migrants and do not establish long-term business roots. Cardinal believes that immigration documents can be revoked by the Immigration and Naturalization Service or other authorities. Cardinal also believes that, because moves are planned months in advance, the moving public needs to be assured that movers will show up on moving day.

De Haven's Transfer states that the issue seems to be whether legal aliens or only United States citizens should be allowed to be certified moving business owners. De Haven's Transfer put forth several arguments in support of allowing only United States citizens to be certified moving business owners. First, De Haven's Transfer argues that proving that someone is truly a legal alien eligible to work involves a full background check. Second, De Haven's Transfer asserts that requiring owners of moving companies to be United States citizens does not limit the hiring of eligible aliens in the moving industry. Third, De Haven's Transfer maintains that it is vital that an owner of a moving company be a United States citizen and a North Carolina resident to ensure the necessary business stability and longevity required to provide the promised services and other related services after the move, such as handling claims. De Haven's Transfer claims that adopting such a requirement would protect the public from movers that do not have solid ties to the area that could leave or possibly be deported at any time. Lastly, De Haven's Transfer observes that felony criminal records for crimes committed outside the United States by aliens may be difficult to obtain.

Dunnagan's Moving supports the Petitioner's proposes changes and states that such changes, along with verification of all information on the application for a certificate of exemption, would help protect and serve the consuming public.

Sells asserts that citizenship provides the most protection to the consumer. In support of this position, Sells argues that if an immigrant were to lose his Green Card status, he could be deported and this could in turn result in a consumer's belongings being left stranded in the deported mover's warehouse.

Smith asserts that non-citizen applicants should be denied a certificate of exemption. Individuals who have not become United States citizens are here on a Visa, which could be revoked at any time by the Immigration and Naturalization Service or other authorities. As such, there is no guarantee that such individuals will be here to provide moving services. There is a need to insure that a certificated mover abides by both state and federal laws concerning employment, taxes, immigration, etc. Individuals who are not United States citizens should not be issued certificates of exemption.

8. **Comments regarding suspected "illegal movers" or uncertificated movers.**

Absolute opines that, in the moving industry, there are people with a valid North Carolina driver's license, United States citizenship, and a clean criminal record doing considerable harm to the reputation of movers, the business of moving HHG in general, and the public. Absolute remarks that more time and energy should be spent focusing on how we can stop these illegal movers, which give the moving industry a bad name by engaging in unethical business practices. In that regard, Absolute observes that it is aware of several movers in Wilmington that are not legal companies.

Armorbearer believes that adding these requirements to the application will add more complexity to the process, prevent rehabilitated citizens from becoming business owners, and cause an increase in the number of illegal moving companies.

Dunnagan's Moving states that it understood that the Commission relaxed the entry process in Docket No. T-100, Sub 49, to allow the many existing illegal operations an opportunity to become "legal" by eliminating the necessity for a showing of need as a prerequisite for coming into compliance with the law. The overall outcome of this process was and is deterioration of the integrity of all certified movers and the creation of an imbalance in competitive conditions. Dunnagan's Moving maintains that the Petitioner's proposed changes in this current docket will protect the public and create a more even level of competition to better serve the public.

Dunnagan's Moving remarks that

> Enforcement is the 'key'!! Without enforcement what good are rules? If no one stops a bank from being robbed, how many bank robbers would there be? If no one stops illegal operations, how many operations will there be? The answer to that question is almost as many as certificated movers are operating today. Right now we compete with PODS, illegal operators, and operations that will fail within 19 months on the average. That alone shows the application process is flawed. Changes are long over due.

Dunnagan's Moving comments that the Commission should make or adjust the rules in the interest of the public. Dunnagan's Moving remarks that moving is a stressful period and that the general public deserves to be able to select a reputable mover that is stable, reliable, and drug free. Dunnagan's Moving points out that the Public Staff was created in 1977 to review, investigate, and make appropriate recommendations to the Commission with respect to standards, regulations, or practices. Dunnagan's Moving opines that the Public Staff should be more active regarding illegal activities and should take strong action to stop illegal movers within North Carolina. Dunnagan's Moving maintains that it has reported 100 or more illegal movers to the Public Staff. Dunnagan's Moving states that it is not satisfied with the Public Staff's efforts, which have consisted of writing a letter or two that resulted in no change in the level of illegal operation. Dunnagan's Moving questions how do the Commission and the Public Staff determine the benefit of allowing the illegal operators to continue and "rubber stamping" every application to transport household goods within North Carolina? Dunnagan's Moving believes that the proposed changes would be a deterrent for illegal operators and would protect the interest of the general public.

Easy Movers states that over the years professional movers have been harmed by the degradation of the industry. There seems to be a void in accountability and a failure to stand up for what is right and to address what is going wrong in the industry. Easy Movers hopes that the Commission will listen to its comments and not allow further erosion of what it has taken a lifetime to build.

Hill observes that it is the Commission's responsibility to maintain the quality of the moving industry since the Commission is the "sole filter for the establishment of moving companies and their owners in" North Carolina. Hill asserts that the mandate of the Commission is to ensure fair trade and consumer protection in North Carolina. Hill complains that the industry has been damaged by "rogue movers" and contends that the moving public wants higher standards that only the Commission can provide.

Ray Moving complains about how badly illegal movers treat the moving public, and points out that they do not pay Commission regulatory fees or any taxes. Ray Moving observes, "In 2005, $61,000,000 worth of revenue was generated by LEGAL movers in North Carolina. This equates to $74,280 of regulatory fees paid to the State of North Carolina. It has been estimated that there are as many illegals as legal movers within the state."

Security Storage asserts that "[t]he first priority should always be to protect the public from any possible manner of harm. . . . Erring on the side of doing all that is possible to ensure the public is protected is of the utmost importance."

WHEREUPON, the Commission reaches the following

CONCLUSIONS

Amendments to Rule R2-8.1

In 2002, the Commission made a fundamental change in the manner in which it regulates motor carriers of household goods. In rejecting complete deregulation of intrastate household good movers, the Commission concluded "that a modified degree of regulation . . . should be maintained, thereby providing a measure of protection to the moving public."[1] The Commission ceased issuing Certificates of Public Convenience and Necessity pursuant to G.S. 62-262 and began issuing certificates of exemption to intrastate household goods movers pursuant to G.S. 62-261(8).[2] G.S. 62-261(8) required the Commission "to attach to such certificate [of exemption] such reasonable terms and conditions as the public interest may require. . . ."[3] Accordingly, in order "to assure continued and adequate levels of protection for the moving public," the Commission has attached terms and conditions to certificates of exemption dealing with fitness and solvency requirements (set forth in G.S. 62-262(e)(2) and (3)) and minimum limits of

[1] Order Ruling on Household Goods Transportation, Docket No. T-100, Sub 49, at 14.
[2] Id. at 15-16.
[3] Id. at 16.

liability insurance coverage and cargo insurance coverage (as provided in G. S, 62-152 and G.S. 62-268) since 2002. In the present docket, Petitioner seeks to have the Commission expand the terms and conditions it attaches to certificates of exemption issued to intrastate household goods movers.

As was the case in 2002, the Commission continues to conclude that a modified degree of regulation of intrastate household goods movers is appropriate and that the current regulatory environment for household goods transportation is of such a nature that certificates of exemption should continue to be issued as provided for in G.S. 62-261(8). Indeed, there is little suggestion in any of the comments filed in this docket that the approach undertaken in 2002 is no longer appropriate. However, the Commission further concludes that the plain language of the statute imposes on the Commission both the right and the obligation "to attach such reasonable terms and conditions as the public interest may require . . ."[1] Accordingly, the question presented in this proceeding is whether imposition of the additional requirements proposed by the Petitioner would be an appropriate exercise of the Commission's clear authority under G.S. 62-261(8) in order to assure continued and adequate levels of protection for the moving public. After careful consideration and review of the comments, reply comments, and the entire record in this docket, the Commission denies the request of Petitioner as set forth in the Petition. However, the Commission concludes that some expansion of the requirements of Rule R2-8.1, in order to obtain additional information relevant to the granting and maintenance of certificates of exemption, would be appropriate.

Any amendments to the existing Commission rule must be carefully constructed in order to assure continued and adequate levels of protection for the moving public and to address the concerns raised by the Petitioner and other commenting parties. In exercising its conditioning authority, the Commission must balance the interests of both the using and consuming public and the interests of applicants and potential applicants for, and holders of, certificates of exemption. In doing so, the Commission must recognize practical considerations concerning the ownership and operation of these businesses in addition to the practical, legal and constitutional limits on its own authority. As the Public Staff argued persuasively in its comments, the United States Supreme Court has recognized the severity of depriving a person of the means of a livelihood[2] and that "[i]t requires no argument to show that the right to work for a living in the common occupations of the community is of the very essence of the personal freedom and opportunity that it was the purpose of the [Fourteenth] Amendment to secure."[3] The right to hold specific private employment and to follow a chosen profession free from unreasonable governmental interference comes within the ambit of both the "liberty" and the "property" concepts found in the Fifth and Fourteenth Amendments.[4] Further, the Supreme Court has consistently interpreted the Fifth and Fourteenth Amendments to apply to all people present in the United States, regardless of their status under the immigration laws.[5] The Commission determines that it can appropriately address the concerns raised by Petitioner and other commentors by modifying its rules to require the certification of compliance with the motor vehicle laws of the state and the

[1] Id.
[2] Loudermill, 470 U.S. at 543.
[3] Raidch, 239 U.S. at 41.
[4] McElroy, 360 U.S. at 492.
[5] Doe, 457 U.S. at 210.

submission of additional information concerning criminal history and immigration status rather than adopting blanket rules prohibiting the issuance of certificates of exemption under the circumstances proposed by Petitioner.

First, the Commission will not require that an applicant have a valid North Carolina driver's license as a precondition for obtaining the issuance of a certificate of exemption. The Commission determines, however, that it is appropriate to require that an applicant for a certificate of exemption be required to certify that any person that the applicant employs to operate a vehicle used to transport household goods will have a valid driver's license. Specifically, the Commission will require that an applicant certify that the applicant will only permit employees with valid driver's licenses to operate vehicles to transport household goods in compliance with the laws of the State of North Carolina.

It would be ineffective, and thus inappropriate, to require the actual applicant for a certificate to possess a valid driver's license. Applicants might be individuals, but an applicant might also be a partnership, corporation, or other business entity incapable of obtaining a valid driver's license. Moreover, even where an applicant is an individual, the individual that possesses the certificate may not be the same individual that operates a motor vehicle and facilitates the actual move. Instead, the important and relevant requirement is that the actual operators of vehicles for the purpose of conducting a household goods move within the state be entitled to lawfully operate such vehicles. In this regard, the Commission will require the applicant to certify to the Commission that any operator of any vehicle used in the transportation of HHG will be properly licensed to operate such vehicle pursuant to the motor vehicle laws of the relevant state.

The Commission sees no legitimate reason for limiting the right to operate an HHG moving business to North Carolina-licensed drivers as suggested by Petitioner. Such a requirement would unnecessarily burden an applicant whose employee does not possess a driver's license issued by the State of North Carolina but nonetheless can lawfully operate a vehicle in the state. To do so would impose on such applicants a burden that is possibly greater than that placed on others operating vehicles on our state's roads in a lawful manner.

The Commission's interest is in protecting the using and consuming public by ensuring that anyone engaging in an HHG move is qualified and lawfully permitted to operate any vehicle being used for the purpose. Amending Rule R2-8.1 to require that an applicant certify that the applicant will only permit employees with valid driver's licenses to operate vehicles used to transport HHG in compliance with the laws of the State of North Carolina is the most appropriate way to accomplish this goal. This approach will place the appropriate burden on the applicant and operator of the intrastate HHG moving business to assure compliance with the motor vehicle laws of the state while avoiding the practical and legal concerns that would arise from placing a burden on intrastate household goods movers that is greater than that placed on the population at large.

Second, the Commission rejects the invitation to adopt an absolute rule with respect to the criminal history of an applicant. However, the Commission determines that it is important to ascertain from the applicant whether the applicant or its principals have been convicted of a crime that might reflect on that person's fitness to engage in the HHG moving business. Therefore, the Commission will require a certified 10-year criminal record check to be filed with each application. In the case of an individual or sole proprietorship, the record should be in the name of the individual completing the application. In the case of an application from a partnership or other corporate form, the Commission expects record checks to be performed on all the partners in a partnership or all the officers in the case of a corporation.

The Commission wants it to be clear that an applicant will not be denied a certificate automatically or solely on the basis that the applicant has a criminal record. Instead, the Commission will review and evaluate the information provided to determine if any conviction or any other aspect of the information provided is relevant to, or would call into question, the applicant's fitness to possess a certificate of exemption. The Commission will consider a variety of factors regarding the conviction in making that determination, including, but not limited to, the severity of the crime, the date of the offense, the nature of the crime as it relates to the duties and responsibilities of a household goods mover, and the applicant's employment, rehabilitation, and other activities since the crime was committed. If the Commission has a concern about any information contained in the applicant's criminal record that it believes might call into question the applicant's fitness to obtain a certificate, the Commission may request additional information or schedule a hearing to allow the applicant an opportunity to be heard before any further action is taken on the application.

The Commission recognizes that applicants and operators may hire employees possessing criminal backgrounds. This is not necessarily a bad thing. Instead, it is a management decision that the Commission believes to lie within the purview of the operator of the business rather than a matter for the Commission should necessarily become involved in addressing. There are obvious practical limitations to the Commission's ability to obtain and review such information concerning every employee of an applicant or operator. More importantly, imposing such a requirement would run the risk of having the Commission become too involved in the management of the businesses providing intrastate HHG moving services in the state. That said, the management and operation of these business, as they affect the public interest, are legitimate interests of the Commission, and should the hiring decisions of a certificate holder and the actions of its employees negatively impact the public interest, the Commission retains the authority to investigate and respond to such circumstances.

Third, the Commission will not implement a requirement that an applicant be a United States citizen as a precondition for obtaining a certificate of exemption. A decision to bar non-citizens from obtaining a certificate of exemption would raise serious constitutional issues. Furthermore, the Commission is not satisfied that there is any reason to believe that individuals lawfully entitled to be in the United States cannot appropriately operate an HHG moving business. On the other hand, the Commission agrees that individuals who are not lawfully in the United States should be issued certificates of exemption. As a result, the Commission determines that it is appropriate to require that all applicants, their principals or owners, disclose their legal status in the United States. In the case of an individual or sole proprietorship, the information should be in the name of the individual completing the application. In the case of an application from a partnership or other corporate form, the Commission expects information to be provided for all the partners or all the officers of a corporation. If an applicant or its principal is not a United States citizen, the individual should provide evidence of some form of employment authorization indicating that he or she is lawfully in the United States. The Commission concludes that possession of a valid form of employment authorization, regardless of citizenship status, by an applicant or its principals, should suffice to permit an applicant to own and operate an intrastate HHG moving business in North Carolina.

As with the issue of criminal history, the Commission recognizes that applicants and operators, like any business, might hire employees who do not possess a valid form of employment authorization. There are, however, obvious practical limitations to the Commission's ability to prevent this from occurring, and, more importantly, there are other government entities with primary responsibility for addressing this problem. That said, the management and operation of these businesses, as they affect the public interest, are legitimate interests of the Commission, and should the hiring decisions of a certificate holder negatively impact the public interest, the Commission retains the authority to investigate and respond to such circumstances.

Having determined that the public interest will be served by requiring additional information concerning lawful operation of motor vehicles, criminal history, and citizenship/employment authorization from applicants for certificates of exemption, an obvious question is presented concerning the appropriate scope and extent of these additional requirements. To the extent that the public interest is served by requiring that this information be provided by new applicants, the public interest also is served by requiring that this information be obtained in other contexts as well. In deciding whether to grant an application to sell, assign, pledge, lease or otherwise transfer a certificate of exemption, just like in deciding whether to grant an application to obtain an initial certificate of exemption, the Commission must find the applicant (i.e., transferee) to be fit, willing, and able to provide the service. Accordingly, the Commission believes that the same requirements applicable to a new application should also be imposed in the event that a certificate is being transferred pursuant to G.S. 62-261(8) and Commission Rules R2-8.1 or R2-9. Similarly, once a certificate of exemption is granted, the Commission retains a continuing obligation to protect the public interest and the authority to revoke a certificate of exemption in appropriate circumstances pursuant to G.S. 62-261(8). The Commission believes that the additional information specified in this order should be required of operators who currently hold certificates of exemption and should be obtained from such current certificate holders at the first reasonable opportunity.

In order to accomplish this result, Rule R2-8.1(b), dealing with the approval of sales, leases or other transfers of certificates of exemption, must be amended in order to make clear that the amendments and additional requirements dealing with new applicants apply and must be conformed to in this context. With respect to existing certificate holders, there are also rule changes that will be necessary to effectuate the Commission's decision. In its first annual report following the issuance of this order and the adoption of the amendments to Rule R2-8.1(a) approved herein, each certificate holder should provide the information being required by Rule R2-8.1(a)(3)e-g, as amended. This obligation will not be an ongoing requirement and will be limited to the first annual report filing following the issuance of this Order. However, in order to fulfill its ongoing responsibility to protect the public interest, the Commission will require that all certificated movers inform the Commission in a timely manner in the event that facts or circumstances relevant to its application or the continuing validity of its certificate of exemption change. Accordingly, each certificated household goods mover should submit with its annual report a certification indicating compliance with the applicable public utility statutes and Commission Rules and stating that no material changes have occurred with respect to the information contained in its initial application and provided to the Commission pursuant to Rule R2-8.1(a)(3), as amended. If there is a change in the information contained in its initial application or provided pursuant to Rule R2-8.1(a)(3), as amended, the certificate holder will have 30 days within which to notify the Commission of this fact.

Finally, having reached the foregoing conclusions with respect to the issues raised by Petitioner, the Commission recognizes that there are certain practical issues raised by the conclusions it has reached. First, any information concerning both criminal history and citizenship/employment authorization shall be filed in a manner that will ensure its confidentiality. The Commission will maintain its confidentiality in a manner consistent with its existing statues, rules and practices. Second, as noted by several commenters, G.S.62-261(8) expressly states that "[n]o certificate of exemption shall be denied, and no order of revocation shall be issued . . . except after reasonable opportunity of hearing of interested parties." The Commission recognizes the right of interested parties to be heard prior to action being taken with respect to a certificate of exemption. By amending Rule R2-8.1 in the manner set forth herein, the Commission does not intend to subvert or impair the right of interested parties to be heard prior to ultimate action being taken concerning a certificate of exemption. With this Order and the amendments promulgated herein, the Commission imposes only a requirement that the additional information be provided by the applicant or operators, but does not prejudge the impact of the information obtained on its ultimate decisions. Instead, the Commission concludes that the information required to be provided as the result of the issuance of this Order will better inform its assessment of whether to grant or revoke a certificate of exemption and to assess the manner in which the business of an operator is being conducted. As required by statute, no ultimate action will be taken in the absence of a reasonable opportunity for interested parties to be heard.

In summary, the Commission finds good cause to expand the specific provisions of Rule R2-8.1 in order to require the provision of additional information relevant to the granting and maintenance of a certificate of exemption. In doing so, the Commission has attempted to balance the policy goals of not unnecessarily increasing the barriers to entry into the HHG moving business while protecting the using and consuming public. While the Commission cannot police all aspects of the operation of an HHG mover, the Commission can seek the representation of the applicant that, in the operation of the business, the motor vehicle laws of the state will be adhered to. The Commission further will request additional information concerning both the criminal history, if any, and immigration status of applicants. This information will be provided confidentially and will assist the Commission in determining the fitness of an applicant to obtain a certificate of exemption. Given that these additional requirements are deemed appropriate for consideration with respect to the granting of a new application and the protection of the public interest, the Commission also is extending them to applications to sell, lease, or transfer a business pursuant to Rules R2-8.1(b) and R2-9. Finally, given the relevance and appropriateness of these requirements at the application stage, the Commission determines that it is appropriate to require that this information be provided by current certificate holders at the first reasonable opportunity and that notice of any changes to the information provided to the Commission should be required as a condition of maintaining good standing under the certificate of exemption.

A copy of the revised Rule R2-8.1 reflecting the foregoing conclusions is attached hereto, as Appendix A, and a copy of the revised application forms for use by future applicants are available on the Commission's website, www.ncuc.net, under Transportation Applications.

Comments on Enforcement

The Commission in its review of the comments submitted by HHG movers notes that some movers have raised concerns about the activities of "illegal" or uncertificated movers. The Commission recognizes that uncertificated movers are a legitimate concern, that uncertificated movers can have a detrimental impact on the integrity of the moving industry, and that the activities of uncertificated movers might jeopardize the property and well-being of the using and consuming public. The Commission has, for example, imposed penalties on at least one uncertified HHG mover. In addition, the Commission has passed along reports of alleged illegal operation to the appropriate state agencies accompanied by a request that the report be properly investigated. On the other hand, the Commission does not have unlimited authority to enforce existing rules and regulations. For example, the Commission does not have enforcement officers with authority to arrest uncertified movers. Instead, that authority is possessed by other agencies of state government. The Commission does believe, however, that further input on the issue is important in order to determine how the Commission might better enforce its rules and regulations given the limitations contained in existing law in order to ensure that uncertificated movers either become certificated or cease doing business entirely. Consequently, the Commission is of the opinion that good cause exists to allow interested parties to file comments on the following issues: 1) Are there ways in which the Commission can improve its requirements for certification and the process for obtaining a certificate such that they may be better understood by potential applicants who are interested in engaging in the intrastate HHG moving industry; 2) Are there ways in which the Commission can improve its enforcement of the requirements contained in existing statutes and Commission rules once an applicant is certified to ensure that he or she remains compliant; and 3) Are there ways in which the Commission can better identify, investigate, pursue, and obtain the prosecution of individuals or businesses that operate in violation of our statutes and rules. The Commission reserves the right to enter, or not enter, additional orders in this docket subsequent to review of such comments.

Comments on these matters should be filed with the Commission in this docket no later than October 1, 2008.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R2-8.1 shall be, and hereby is amended as set out in Appendix A, attached hereto, effective as of the date of this Order.

2. That, in connection with its first annual report following the issuance of this Order and the adoption of amendments to Rule R2-8.1(a) promulgated herein, each current holder of a

certificate of exemption pursuant to G.S. 62-261(8) should provide the information being required by Rule R2-8.1(a) (3)e-g, as amended.

3. That interested parties may file comments on the following issues: 1) Are there ways in which the Commission can improve its requirements for certification and the process for obtaining a certificate such that they may be better understood by potential applicants who are interested in engaging in the intrastate HHG moving industry; 2) Are there ways in which the Commission can improve its enforcement of the requirements contained in existing statutes and Commission rules once an applicant is certified to ensure that the applicant remains compliant; and 3) Are there ways in which the Commission can better identify, investigate, pursue, and obtain the prosecution of individuals or businesses that operate in violation of our statutes and rules. Such comments shall be filed with the Commission not later than October 1, 2008.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of August, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Kc082908.04

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R2–8.1. APPLICATIONS FOR CERTIFICATES OF EXEMPTION; TRANSFERS; AND NOTICE

(a) For New Applications.

(1) Application to operate as a common carrier of household goods must be made on forms furnished by the Commission, and all the required exhibits must be attached to and made a part of the application. The original and three (3) complete copies of the application, including exhibits, must be filed with the Commission with a fourth copy for the Public Staff's Transportation Division.

(2) The application shall be signed and sworn to by the applicant. If the applicant is a partnership, one partner may sign and verify for all; but the names and addresses of all partners must appear in the application and a certified copy of the partnership agreement, as filed in the county wherein the principal office of the partnership is located, must be filed with the Commission. <u>This does not alleviate the responsibility that all the partners or principals are required to submit individual certified criminal records and citizen certifications or employment authorization as set forth in Rule R2-8.1(a)(3)(f and g).</u> Trade names will not be allowed unless the names and addresses of all owners are given. If the applicant is a corporation, a duly authorized officer of the corporation must verify the application. The names and addresses of the principal managing officers of the corporation must be given and a certified copy of the corporate charter filed with the application.

(3) Pursuant to G.S. 62-261(8), the applicant shall provide proof <u>or certification</u> of the following:

a. That the applicant is fit, willing, and able to properly provide the transportation of household goods in intrastate commerce and has a reasonable and adequate knowledge of the moving industry;

b. That the applicant is financially solvent and able to furnish adequate service on a continuing basis, including adequate insurance protection, maintenance of safe, dependable equipment, and the financial ability to settle any damage claims for which it is liable;

c. That the applicant maintains minimum limits of liability insurance coverage of $100,000/$300,000/$50,000, or such higher amount may be required by federal law, and cargo insurance coverage of $35,000/$50,000;

d. That the applicant maintains a minimum amount of $50,000 general liability insurance coverage;

e. That the applicant certifies that only persons possessing valid driver's licenses will operate the motor vehicles that will be used for transporting household goods;

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f. That the applicant or all its partners/principals submit a certified criminal history records check for the immediately preceding 10-year period; and

g. That the applicant or all its partners/principals certifies that he or she (1) is a United States citizen or (2) if not a United States citizen, to submit employment authorization document(s) proving legal status to work within the United States.

(b) For Approval of Sale, Lease, or Other Transfer of Certificate of Exemption. (Also see Rule R2-9.)

(1) Application for approval of sale, lease, or other transfer of certificate of exemption shall be typewritten, shall be filed with the Commission with a copy to the Public Staff, by providing an original and three (3) copies. Such applications may necessarily differ according to the nature of the transaction involved, but must include the following:

a. The names and addresses of all parties to the transaction.

b. A full and complete explanation of the nature of the transaction and its purpose.

c. That the applicant or all its partners/principals complete the requirements set forth in R2-8.1(a)(3).

(2) If the application is for approval of a lease of certificate of exemption, a copy of the proposed lease agreement must be filed with the application and must contain the entire agreement between the parties.

(3) If the application is for approval of a sale of certificate of exemption, a copy of the proposed sales agreement must be filed with the application and must contain the entire agreement between the parties, including the purchase price agreed upon, and all the terms and conditions with respect to the payment of same.

(4) No sale of a certificate of exemption will be approved unless the seller complies with the provisions of G.S. 62-111 by filing a statement under oath, as therein required, with respect to debts and claims; a statement showing gross operating revenues and total number of miles traveled for the latest three months' period preceding the date of filing the application, or for the latest three months' period preceding the date of authority to suspend operations, if theretofore granted by this Commission; and no such sale will be approved unless the purchaser files with the Commission a statement under oath attesting to his fitness and ability to provide household goods transportation service and of his assets and liabilities from which it must appear that the purchaser is solvent and in financial condition to meet such reasonable demands as the business may require.

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(5) If the transferee is a corporation, a certified copy of its corporate charter must be filed with said application unless same is already on file with the Commission.

(6) If the application is for approval of a merger of two or more carriers, or of any agreement by which one carrier seeks to acquire an interest in or control over another carrier, the application shall set out the purpose of such merger, combination or agreement, and the extent of any transfers of other properties of the carriers involved, the changes in the financial status and obligations of the individual carriers involved, and all other matters necessary to a full understanding of the transaction and its effect upon other motor carriers.

(c) Notice of Application and Hearings.

(1) Upon receipt of an application for a certificate of exemption for the transportation of household goods, same shall be made available for review on the Commission's website. Any party desiring to file a protest must do so in writing by setting forth the reasons for the protest and filing that protest with the Commission no later than 15 days from the filing date of the application. Protests may be filed based only upon the applicant's fitness or financial solvency.

(2) If no protests are filed to the application within the 15-day time period provided for in Rule R2-8.1(c)(1), or as extended by order of the Commission, the Commission may proceed to decide the application on the basis of information contained in the application and such additional information as the Commission may choose to obtain.

(NCUC Docket No. T-100, Sub 49, 02/02/04; NCUC Docket No. T-100, Sub 69, 8/29/08)

Docket No. T-100, Sub 69

COMMISSIONER ROBERT V. OWENS, JR., DISSENTING IN PART: I am respectfully dissenting from the portion of the majority's order that requires applicants for certificate of exemption to provide criminal background checks and to submit employment authorization documents. The Petitioner initiated this docket under the guise of promoting safety for the using and consuming public and creating stability in the moving industry. However, the

Petitioner in my opinion has not provided sufficient justification for amending Commission Rule R2-8.1.

I believe that the Commission has exceeded its jurisdiction in this matter by requiring these documents. Although the majority has stated that the information will not be used to deny an applicant without first having a hearing and opportunity to be heard, the requirement of these documents will have a chilling effect on otherwise interested individuals who may have a criminal record or who happen to be an undocumented person from applying for a certificate of exemption.

Overall, I believe the effect of the requirements put forth by the Petitioner and modified by the Commission will adversely limit competition in the household goods moving industry and possibly create more uncertificated movers.

/s/ Robert V. Owens, Jr.
Commissioner Robert V. Owens, Jr.

DOCKET NO. T-100, SUB 69

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Petition by Movin' On Movers, Inc. to Amend	)	ERRATA ORDER
Rule R2-8.1 Applications for Certificates of	)	
Exemption; Transfers; and Notice	)	

BY THE COMMISSION: On August 29, 2008, the Commission issued an Order Amending Rule R2-8.1 And Allowing Additional Comments in the above identified docket. The Order set forth the Commission's conclusions to the Petition to Amend Rule R2-8.1 filed by Movin' on Movers on August 28, 2007.

It has come to the attention of the Commission that the word "not" was inadvertently omitted from the fourth sentence of the second full paragraph on page 28 of the Order. That full paragraph should read as follows:

Third, the Commission will not implement a requirement that an applicant be a United States citizen as a precondition for obtaining a certificate of exemption. A decision to bar non-citizens from obtaining a certificate of exemption would raise serious constitutional issues. Furthermore, the Commission is not satisfied that there is any reason to believe that individuals lawfully entitled to be in the United States cannot appropriately operate an HHG moving business. On the other hand, the Commission agrees that individuals who are not lawfully in the United States should **not** be issued certificates of exemption. As a result, the Commission determines that it is appropriate to require that all applicants, their principals or owners, disclose their legal status in the United States. In the case of an individual or sole proprietorship, the information should be in the name of the individual completing the application. In the case of an application from a partnership or other corporate form, the Commission expects information to be provided for all the partners or all the officers of a corporation. If an applicant or its principal is not a United States citizen, the individual should provide evidence of some form of employment authorization indicating that he or she is lawfully in the United States. The Commission concludes that possession of a valid form of employment authorization, regardless of citizenship status, by an applicant or its principals, should suffice to permit an applicant to own and operate an intrastate HHG moving business in North Carolina.

The Commission finds good cause to issue this errata order.

IT IS, THEREFORE, SO ORDERED

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of August, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Kc082908.06

DOCKET NO. T-100, SUB 69

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Petition by Movin' On Movers, Inc. to Amend	)	SECOND ERRATA ORDER
Rule R2-8.1 Applications for Certificates of	)	
Exemption; Transfers; and Notice	)	

BY THE COMMISSION: On August 29, 2008, an Errata Order was issued in this docket noting that the word "not" was inadvertently omitted from the fourth sentence of the second full paragraph on page 28 of the Order Amending Rule R2-8.1 And Allowing Additional Comments.

The Order further inadvertently did not indicate that Commissioner Robert V. Owens, Jr., dissented in part to the majority's decision. The dissent was attached as the last page of the Order. At the bottom of page 32 of the Order, the following statement should have been included:

Commissioner Robert V. Owens, Jr., dissents in part.

The Commission finds good cause to issue a second errata order in this docket.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of August, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

kh082908.01

DOCKET NO. W-100, SUB 46
DOCKET NO. WR-100, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Year 2007 Drought Response -	)	ORDER MODIFYING RESTRICTIONS
Water Conservation Measures	)	CONCERNING NONESSENTIAL WATER USAGE
	)	AND REQUIRING NOTICE

BY THE COMMISSION: On October 24, 2007, the Commission issued an Order Requiring Curtailment of Nonessential Water Usage in the above-captioned dockets. Following issuance of said Order, the drought continued to worsen until the end of December. Since that time, the State has been receiving beneficial precipitation. While the drought is certainly not over, conditions have improved to the point that it seems to be appropriate to relax the Commission-mandated restrictions in certain areas in certain respects.

In October 2007, the statewide nature of this exceptional drought warranted the drastic action taken by the Commission which required the curtailment of all nonessential water usage. As the drought eased somewhat and as some anomalies in the effects of the nonessential water use restrictions previously adopted by the Commission have been detected, the Commission identified several areas within the State in which it considered releasing or relaxing some of the presently imposed restrictions on water usage that have been in place since October 24, 2007. Therefore, on May 1, 2008, the Commission issued an Order Requesting Comments regarding its proposals to modify the October 24, 2007, Order. Such comments were required to be filed by the Public Staff and any other interested parties by May 14, 2008. The Commission received comments from the Public Staff, Aqua North Carolina, Inc., Carolina Water Service, Inc. of North Carolina, and several interested customers. The Commission has carefully considered these comments in determining that the water usage restrictions imposed in the October 24, 2007, Order should be modified in the following respects.

The Commission's proposals relating to Purchased-Water Systems and Cumberland County Type Circumstance were not controversial. Instead, all parties recommended the adoption of those proposals. As a result, the Commission concludes that they should be adopted as follows.

1. <u>Purchased-Water Systems</u>

While a majority of the water systems throughout North Carolina regulated by the Utilities Commission acquire their water from utility-owned wells, many systems purchase their water from other sources and resell the water to their customers.

All of the companies classified as water resellers (identified by docket numbers that begin with "WR") purchase their water from municipal sources that are not regulated by the Commission. The Commission is of the opinion that it is inconsistent for customers of water resellers to be subject to different nonessential water usage restrictions than the municipal customers who receive water from the same source. Therefore, the Commission will allow "WR" customers to be subject to the same water restrictions regarding nonessential water usage that have been imposed by the local municipality from which the water that they consume is being purchased.

Furthermore, a number of traditional water utilities (those with docket numbers beginning with "W") operate certain systems that, for various reasons, purchase water from a municipality for resale to their customers. It is, likewise, inconsistent for customers served by these purchased-water systems to be subject to restrictions regarding nonessential water usage that are different from those to which municipal customers utilizing the same source of water are subject. Therefore, the Commission will require the water utility companies to identify all of their specific systems utilizing purchased water and to notify the customers on those systems that they will be subject to the same water restrictions that are imposed by their local municipality that supplies their utility provider with water. The water utility is hereby required to provide the Commission with a listing (including subdivision name, county name, name of supplier, and number of customers) of all service areas so identified within twenty days of this Order.

2. <u>Cumberland County-Type Circumstance</u>

The Commission is aware of a large service area franchised to Aqua North Carolina in the Cumberland County area that uses well water to serve a portion of the service area and that also uses water purchased from the Fayetteville Public Works Commission (PWC) to provide service in another portion of the service area.

As discussed above, the Commission believes it is incongruous for customers whose source of water is water purchased from an entity like the PWC to be subject to restrictions regarding nonessential water usage that are different from those applicable to customers served by entities like the PWC. The Commission is of the opinion that these customers should be subject to the restrictions for nonessential water usage adopted by the PWC or a similar entity. However, it would be very confusing for customers within the same service area to be subject to two different sets of water usage restrictions. Therefore, the Commission believes that it would be appropriate to require the utility in such a situation to identify the systems utilizing both purchased water and well water and notify the customers served by these systems that they will be subject to the same water restrictions imposed by their local municipality from which a portion of their water supply is purchased. The utility is required to provide the Commission with a listing (including subdivision name, county name, name of supplier, and number of customers with well water and the number of customers with municipal-supplied water) of all service areas so classified within twenty days of this Order. This approach is not applicable solely to the Cumberland County situation described above, but may be implemented anywhere a similar situation exists which has been properly identified for the benefit of the Commission.

3. <u>Remainder of the Proposals</u>

The remainder of the proposals (Coastal Counties, Metrolina Counties, and Remainder of the State) set out in the Commission's May 1, 2008, Order were the subject of many comments, remarks, and observations. As noted earlier, the beneficial rains of late winter have caused the effects of the drought to lessen. As soon as reservoirs filled up, many municipalities relaxed their water restriction guidelines relating to nonessential water usage. This rush to relax existing water usage restrictions was followed by a press release from Governor Easley in which he noted that he had written a letter to local officials asking them to continue their aggressive water conservation efforts because the drought is not over. The Commission has not joined in the premature rush to relaxation of restrictions.

The North Carolina Drought Management Advisory Council (DMAC) maintains a website on which the North Carolina portion of the United States Drought Monitor's drought severity map is displayed. This map showing the location and the severity of the drought is updated weekly. The DMAC urges implementation of drought response actions for all users located in or dependent on water resources derived from areas experiencing exceptional, extreme, severe, or moderate drought or abnormally dry conditions.

Based upon the DMAC's reclassification of the severity of the drought across the State, the recommended drought response actions, and the comments submitted by the parties, the Commission finds and concludes that it is appropriate to relax some of its existing restrictions depending upon the drought severity classification applicable to specific areas (the Commission-regulated water systems located within a particular area composed of specific counties will be subject to the water restrictions as defined by the Commission below). The Commission will maintain a webpage entitled *Non-Essential Water Usage Restrictions*, on its website, www.ncuc.net, whereupon the varying restrictions will be listed by drought severity classifications. The webpage will contain a hyperlink to the DMAC drought severity map. The level of restrictions applicable to a particular county will vary as the DMAC drought severity map classifications change from week to week every Thursday. For this purpose, the official drought severity classification for each county will be designated in accordance with DMAC's placement of each county in its listing for "Counties Under Current Advisory." The entire county is designated under a single classification which is based upon the highest level of drought severity applicable to any portion of the county in question.

Normal Conditions
(No drought classification – counties that are completely white on DMAC's map)

Voluntary odd-even spray irrigation three days per week:

Odd addresses:	Tuesday 10 p.m. to Wednesday 4 a.m.
	Thursday 10 p.m. to Friday 4 a.m.
	Saturday 10 p.m. to Sunday 4 a.m.
Even addresses:	Wednesday 10 p.m. to Thursday 4 a.m.
	Friday 10 p.m. to Saturday 4 a.m.
	Sunday 10 p.m. to Monday 4 a.m.

Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable at anytime.

Car washing is allowable at anytime.

Filling of swimming pools or topping-off pools is allowable at anytime.

D0 Abnormally Dry
(Yellow on DMAC map)

Mandatory odd-even spray irrigation three days per week:

Odd addresses:	Tuesday 10 p.m. to Wednesday 4 a.m.
	Thursday 10 p.m. to Friday 4 a.m.
	Saturday 10 p.m. to Sunday 4 a.m.
Even addresses:	Wednesday 10 p.m. to Thursday 4 a.m.
	Friday 10 p.m. to Saturday 4 a.m.
	Sunday 10 p.m. to Monday 4 a.m.

Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable at anytime.

Car washing is allowable at anytime.

Filling of swimming pools or topping-off pools is allowable at anytime.

D1 Moderate Drought
(Beige on DMAC map)

Mandatory odd-even spray irrigation two days per week:

Odd addresses:	Tuesday 10 p.m. to Wednesday 4 a.m.
	Thursday 10 p.m. to Friday 4 a.m.
Even addresses:	Wednesday 10 p.m. to Thursday 4 a.m.
	Friday 10 p.m. to Saturday 4 a.m.

Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable at anytime.

Car washing is allowable at anytime.

Filling of swimming pools or topping-off pools is allowable at anytime.

D2 Severe Drought
(Light Orange on DMAC map)

Mandatory odd-even spray irrigation two days per week:

Odd addresses:	Tuesday 10 p.m. to Wednesday 1 a.m.
	Thursday 10 p.m. to Friday 1 a.m.
Even addresses:	Wednesday 10 p.m. to Thursday 1 a.m.

Friday 10 p.m. to Saturday 1 a.m.

Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable on any day (8 p.m. to 8 a.m.).

Car washing – odd addresses on Saturday/even addresses on Sunday.

No filling of swimming pools - Topping-off pools only 12 inches per week.

D3 Extreme Drought
(Red on DMAC map)

Mandatory odd-even spray irrigation one day per week:

Odd addresses:	Tuesday 10 p.m. to Wednesday 1 a.m.
Even addresses:	Wednesday 10 p.m. to Thursday 1 a.m.

Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable on any day (8 p.m. to 8 a.m.).

Car washing – odd addresses on Saturday/even addresses on Sunday.

No filling of swimming pools – No topping-off pools.

D4 Exceptional Drought
(Burgundy on DMAC map)

No spray irrigation.

Handheld use of a container or hose to water flowers, shrubs, trees, and vegetable gardens is allowable on any day (8 p.m. to 8 a.m.).

No car washing.

No filling of swimming pools – No topping-off pools.

4. **Other Considerations**

A concern expressed by certain customers was that some neighboring customers are violating the current water restrictions without consequence. The companies have commented on the cumbersome nature of the existing procedures that require catching a violator in the act, documenting the violation, warning the violator, asking the Commission for authority to disconnect the violator upon the next violation, receiving permission from the Commission to disconnect the customer, serving the Order granting permission to disconnect on the customer, and witnessing a subsequent violation before a violator may be disconnected. Based upon the foregoing, the Commission is of the opinion that the existing enforcement procedures should be streamlined and that a regulated water company should be allowed to disconnect a water customer if he or she violates the restrictions set out in this Order. However, a customer must be provided a 24-hour notice prior to disconnection (for this purpose a door hanger type notice will be sufficient). The customer will have a full business day[1] after the date of notification to show cause why his or her service should not be disconnected. A customer seeking to show cause why his or her service should not be disconnected should contact the Operations Division of the Commission by telephone at (919) 733-3979. If the customer does not successfully show cause, the utility may disconnect service at the end of the next business day. The utility shall immediately notify the Commission when it disconnects a customer's service for violation of these nonessential water usage restrictions. Except as modified in this Order, the other enforcement procedures specified in the Commission's October 24, 2007, Order remain in full force and effect.

The Commission is also of the opinion that the water companies should be required to provide periodic nonessential water usage restriction updates to their customers by bill inserts and inform customers that they may call their local water utility provider to check on the current water usage restrictions for their county.

Several other suggestions (such as monetary penalties for violations, penalties based on excessive usage as determined by meter readings instead of witnessing a violation, and inclining block rates (tiered rates), etc.) were advanced by various commenters. While not adopting these ideas at this time, the Commission will take these and other suggestions under advisement and reserves the right to implement additional restrictions or enforcement measures in the event that the Commission has the authority to implement such measures and believes that their implementation would be appropriate. The Commission does, however, note that is has significant concerns about the extent of its authority to authorize utilities to impose monetary penalties on customers violating water usage restrictions.

Based upon the foregoing, the Commission is of the opinion that it should modify the restrictions which were put in place by the Order issued on October 24, 2007, as noted above, and it should require that a copy of this Order be mailed with sufficient postage or be hand delivered by all Commission-regulated water and water resale companies to all customers no later than 10 days after the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of May, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb052008.01
Commissioners Robert V. Owens, Jr., and James Y. Kerr, II, did not participate.

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[1] A "business" day does not include weekends or holidays. As a result, a Commission-regulated water utility may not disconnect a customer for violating these restrictions on nonessential water usage until after one business day has elapsed after the notice of disconnection has been provided to the affected (e.g., if the notice is provided on Tuesday, service may be discontinued on Thursday, or if notice is provided on Saturday, service may be discontinued on Tuesday).

DOCKET NO. W-100, SUB 46
DOCKET NO. WR-100, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Year 2007 Drought Response - Water Conservation Measures	)	ORDER OF CLARIFICATION

BY THE COMMISSION: On May 23, 2008, the Commission issued an Order Modifying Restrictions Concerning Nonessential Water Usage and Requiring Notice in the above-captioned matter. On May 28, 2008, Utilities, Inc. (UI), filed a Motion for Clarification in the matter.

UI noted that several of their subsidiaries own and operate several water systems that extend into more than one county. As a result of the geographic location of these systems, situations may arise where a system extends into two counties with different drought classifications. Based on the May 20, 2008, DMAC drought severity map (the map in existence at the time the Order Modifying Restrictions was issued), Cabarrus County was classified as a severe drought category and Mecklenburg County was classified as an extreme drought category. The service area of Cabarrus Woods Subdivision (owned by Carolina Water Service, Inc., of North Carolina) lies in both counties. In the example given above by UI, customers in one end of the subdivision could irrigate twice a week, while customers in the other end could only irrigate once a week. UI noted that this could be very confusing to the customers and could hamper enforcement efforts by the utility.

UI requested that the Commission issue an Order clarifying what level of water restrictions should be applied to a water system in multiple counties with different drought designations.

Based upon the foregoing, the Commission is of the opinion that an Order should be issued clarifying that, in the case of water system located in two counties with differing drought designations, the drought designation for such a subdivision would be the higher of the two designations (In the example above, extreme drought is D3 and severe drought is D2, therefore Cabarrus Woods would come under the restrictions for extreme drought).

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of June, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

rb061008.02

DOCKET NO. E-2, SUB 929

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Authority to Adjust Its Electric Rates and Charges Pursuant to G.S. 62-133.2 and NCUC Rule R8-55	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, September 16, 2008, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin IV, Presiding; Chairman Edward S. Finley, Jr.; Commissioner Lorinzo L. Joyner; Commissioner Howard Lee; and Commissioner William T. Culpepper III

APPEARANCES:

For Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel, Progress Energy Carolinas, Inc., Post Office Box 1551, PEB 17A4, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Antoinette Wike, Chief Counsel, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Len Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609-6622

For the Carolina Industrial Group for Fair Utility Rates II:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602-1357

BY THE COMMISSION: On June 6, 2008, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. ("PEC" or "the Company"), filed an Application and accompanying testimony and exhibits pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities. PEC's Application also requested that the Commission extend the current Experience Modification Factor ("EMF") approved in Docket No. E-2, Sub 903, for an additional two months through November 30, 2008.

On June 13, 2008, the Commission issued an Order Scheduling Hearing, Establishing Discovery Guidelines, Requiring Notice and authorizing PEC to make a tariff filing extending its current EMF through November 30, 2008. PEC filed its revised Fuel Cost Adjustment Rider tariff on July 28, 2008, and provided notice in newspapers of general circulation as required by the Order.

On June 11, 2008, the Carolina Utility Customers Association, Inc. ("CUCA"), filed a petition to intervene. On June 23, 2008, the Carolina Industrial Group for Fair Utility Rates II ("CIGFUR II") filed a petition to intervene. The Commission allowed the interventions of CIGFUR II and CUCA on June 13, 2008, and June 24, 2008, respectively. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On June 23, 2008, the Attorney General (AG) filed a notice of intervention, which is recognized pursuant to G.S. 62-20.

On September 5, 2008, PEC filed the supplemental testimony and exhibits of Bruce Barkley, which included a Settlement Agreement entered into by the Public Staff, PEC, CIGFUR II, and CUCA. Also on September 5, 2008, the Public Staff filed a notice of affidavits and the affidavits of Thomas S. Lam, Randy Edwards, and Sonja R. Johnson.

The case came on for hearing as scheduled on September 16, 2008. Three public witnesses appeared at the hearing; Herman Jaffe, Marvin Woll, and Ray Cooksey. The prefiled testimony and exhibits of PEC witness Dewey Roberts were received into evidence, and Bruce Barkley, Manager-Fuel Forecasting and Regulatory Support for PEC, presented direct testimony on behalf of the Company. The Commission admitted into evidence the affidavits of Public Staff witnesses Thomas S. Lam, Utilities Engineer, Electric Division, and Randy Edwards and Sonja R. Johnson, Staff Accountants, Accounting Division. No other party presented witnesses.

The parties filed briefs and proposed orders on October 15, 2008.

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

FINDINGS OF FACT

1. PEC is a duly organized corporation existing under the laws of the State of North Carolina and is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. PEC is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.2 and Commission Rule R8-55.

2. The test period for purposes of this proceeding is the 12-month period ended March 31, 2008.

3. PEC's fuel and fuel-related practices and procurement costs during the test period were reasonable and prudent.

4. The performance of PEC's base load plants during the test period was reasonable and prudent.

5. Setting fuel costs associated with purchases from power marketers and certain other sellers for the period April 1, 2007, through December 31, 2007, at a level equal to 61% of the energy portion of the purchase price is reasonable for purposes of determining PEC's EMF in this proceeding.

6. The projected fuel and fuel-related costs for use in this proceeding are $1,252,013,048. This amount consists of $139,370,127 of non-capacity purchased power costs, $15,539,260 of qualifying facility capacity costs and renewable energy costs, and $1,097,103,661 of other fuel and fuel-related costs. Consistent with G.S. 62-133.2(a2), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed 2% of PEC's total North Carolina jurisdictional gross revenues for 2007.

7. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection was $203,363,040. As permitted by G.S. 62-133.2(d) and Commission Rule R8-55(d)(3), PEC included in the calculation of its EMF its under-recovered fuel cost through July 31, 2008. The under-recovery also reflects allowed interest and adjustments resulting from the marketer adjustment and adjustments agreed to by PEC and the Public Staff.

8. The uniform bill adjustment methodology proposed by PEC, CIGFUR II, CUCA, and the Public Staff is just and reasonable and should be approved for the purpose of this proceeding.

9. The provision of the Settlement Agreement to spread the recovery of PEC's fuel and fuel-related cost under-recovery as of July 31, 2008, over three years with interest is just and reasonable and should be approved for the purpose of establishing the appropriate EMF to adopt in this proceeding.

10. Consistent with the cost allocation requirements of G.S. 62-133.2(a2)(1) and the Settlement Agreement, the proper composite fuel and fuel-related costs factors for this proceeding for each of PEC's rate classes, excluding gross receipts tax and regulatory fee[1], are as follows: 3.350¢/kWh for the Residential class; 3.419¢/kWh for the Small General Service class; 3.154¢/kWh for the Medium General Service class; 3.040¢/kWh for the Large General Service class; and 4.319¢/kWh for the Lighting class.

11. The appropriate EMF to adopt for the purpose of this proceeding is an increment of 0.180¢/kWh, excluding gross receipts tax.

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[1] PEC proposed fuel and fuel related costs factors with and without gross receipts tax. The Public Staff testified as to the factors excluding gross receipts tax. However, it is appropriate for the rates schedules to reflect both gross receipts tax and the regulatory fee.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel and fuel-related charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending March 31st as the test period for PEC. PEC's filing was based on the 12 months ended March 31, 2008. In its Order Adopting Final Rules issued on February 29, 2008, in Docket No. E-100, Sub 113, the Commission amended Commission Rule R8-55 to allow a utility to include its under- or over-recovery of fuel and fuel-related costs through the date that is 30 calendar days prior to the date of the hearing and to move PEC's hearing date from the first Tuesday in August to the third Tuesday in September. The amendments also changed the deadline for filing the information required under Rule R8-55 so that the filing must be made at least 90 days prior to the hearing and changed the effective date of any rate change resulting from such a proceeding to no later than 180 days from the filing date in this proceeding, which makes any rate change resulting from the Commission's decision in this proceeding effective on or about December 1, 2008.

The test period proposed by the Company was not challenged by any party, and the Commission concludes that the test period appropriate for use in this proceeding is the twelve months ended March 31, 2008.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 & 4

The evidence for these findings can be found in PEC's Application and the monthly fuel reports on file with the Commission, as well as the testimony of PEC witnesses Barkley and Roberts and the affidavits of Public Staff witnesses Edwards and Lam.

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. PEC's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on June 2, 2008, and were in effect throughout the 12 months ending March 31, 2008. In addition, PEC files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). PEC also files monthly reports of its fuel costs pursuant to Rule R8-52(a). These reports were filed in Docket No. E-2, Sub 898 for calendar year 2007 and in Docket No. E-2, Sub 919 for calendar year 2008.

PEC witness Barkley described in detail PEC's coal and gas procurement practices. PEC relies on short-term and long-term simulation models to estimate the coal and gas requirements of its generating plants. Using this information in conjunction with plant inventory levels and supply risks, a determination is made of the coal requirements at that time. Once this determination is made, coal suppliers are contacted and asked to submit bids to meet the coal requirements. Coal contracts are awarded based on economic evaluation, supplier credit review, past performance, and coal specifications. Gas contracts follow a similar process. During the test period, PEC purchased coal at an average price of $73.09 per ton and gas at $8.33/mmBtu, excluding fixed costs.

Witness Barkley further testified that PEC continuously evaluates the term and spot markets for fuel and purchased power in order to determine the appropriate portfolio of long-term and spot purchases that ensures a reliable supply of electricity to customers at the lowest reasonable prices. Such evaluations include daily, weekly, and monthly solicitations and subscriptions to fuel pricing services and trade publications. Witness Barkley concluded that PEC prudently operated its generation resources and purchased power during the period under review in order to minimize its costs.

Witness Barkley testified that, during 2008, there was an extreme increase in coal prices as illustrated on Barkley Exhibit No. 2. Market prices at the mine for non-compliance Central Appalachia ("CAPP") coal delivered via the Norfolk & Southern ("NS") railway nearly doubled from $60 per ton to $116 per ton as of the end of May. These prices reached record-high levels during May 2008 and have retreated only slightly. Similar increases have been experienced for all types of coal from the CAPP region. He explained that this unprecedented surge in coal prices is driven by many factors. The primary cause is the huge demand for coal-fired electricity in China, India, and other developing nations. This growth caused an increase of 30% in worldwide coal consumption from 2001 to 2006 according to the United States Energy Information Administration. During that period, the growth in China's consumption of electricity exceeded Japan's total current annual consumption. Due to cost advantages over competing fuels and more affordable modes of transportation, coal continues to be the primary fuel source as these developing nations add electric generation at a rapid pace. In addition to the ever-increasing worldwide demand for coal-fired electric generation, the price of coal used in steel making has tripled recently to over $300 per ton in response to heavy worldwide demand for steel.

Witness Barkley further explained that there have also been some specific situations which have hastened the rise in coal prices experienced during 2008. These situations include a self-imposed moratorium on coal exports by China as extreme winter weather combined with growing demand led to electrical shortages there. Indonesia, a major coal exporter, has warned that it may curb future exports in order to meet its growing domestic coal needs. Australia, another major coal exporter, experienced severe flooding which hampered mining and shipping delays. South Africa experienced mining problems due to electrical shortages. Russian exports were interrupted by rail car shortages and political disputes. These events have increased the demand for South American and United States coal in the European market as sources traditionally delivered to Europe have either been interrupted or routed elsewhere. The devaluation of the United States dollar has also made American coal attractive in Europe. Finally, the fact that coal, even at these elevated prices, is still less expensive than natural gas or oil alternatives on a per Btu basis has further supported an increase in United States coal exports.

Witness Barkley testified that, during 2009, which is the majority of the forecasted period in this proceeding, certain PEC existing coal contracts expire. In order to ensure a reliable supply of coal to meet the needs of its customers, PEC has executed replacement contracts. While these contracts are at prices that are higher than the contracts that expired, they are the result of a request for proposals, and the ultimate prices obtained are lower than current market prices. He noted that certain eastern United States utilities have recently issued requests for coal proposals and received no bids. This highlights the short supply of coal that currently exists.

Witness Barkley stated that PEC recognizes that receipt of coal under contract at prices that are lower than current market prices will be very important. Therefore, in accordance with procedures outlined in Barkley Exhibit No. 1, PEC will carefully monitor those receipts to ensure compliance with the established contracts. In addition, he stated that PEC is continuing to migrate to higher sulfur coals, which will provide supply flexibility and potential cost savings. PEC will continue to monitor non-traditional sources of coal supply and will pursue such opportunities if they prove to be cost effective. Finally, PEC will continue to adhere to its disciplined, long-term strategy of procuring most of its coal under contractual arrangements of varying lengths and vintages, supplemented with market purchases as appropriate.

Witness Barkley testified that PEC has installed and is operating wet scrubbers at its two generating units located near Asheville, North Carolina, and at three of the four units at its Roxboro generating facility. The other Roxboro unit will have a scrubber installed and operating during 2008, and a scrubber installation is planned for the Mayo unit in the spring of 2009. Upon completion of the installation of the two remaining wet scrubbers, PEC will have the flexibility and capability to purchase higher sulfur coal for approximately 75% of its annual coal requirement.

Witness Barkley explained that, in today's volatile market, the future relationship between the price of higher sulfur coal and the lower sulfur coals that PEC has traditionally consumed at the locations that either currently have or will have scrubbers installed cannot be predicted with certainty. However, as with the procurement of any product, increased flexibility in coal selection will provide benefits as PEC seeks future supplies. Witness Barkley further explained that the cost advantage that previously existed on a delivered basis for high sulfur coals from Northern Appalachia and the Illinois Basin has eroded as a result of greater demand for these coals and associated transportation. At this time, the most economical coal for PEC's units with scrubbers is a higher sulfur, approximately 2.5 lbs. SO_2/mmBtu, coal from the CAPP region.

With regard to PEC's cost to transport the coal it consumes at its generating units, PEC witness Barkley stated that coal is generally transported via the CSX or the NS railway. PEC receives a limited amount of coal by truck at Asheville and foreign coal by barge at the Sutton Plant located near Wilmington. The Roxboro and Mayo Plants, PEC's largest coal plants, and the Asheville Plant are served solely by NS. The Robinson, Weatherspoon, and Sutton Plants are served solely by CSX. The Lee and Cape Fear Plants can be served by both CSX and NS. To minimize transportation costs, PEC negotiates the most advantageous rates possible. PEC, through a consortium of shippers, participates in proceedings before the Federal Surface Transportation Board in an attempt to lower its rail costs. PEC's use of water and truck transportation demonstrates its commitment to diversification of coal transportation.

With regard to PEC's cost of natural gas, witness Barkley testified that natural gas prices have recently reached extremely high levels in response to very high crude oil prices of approximately $130 per barrel, strong demand for natural gas worldwide, and decreased levels of domestic storage as compared to historical highs experienced in 2007. Strong global demand for liquefied natural gas (LNG) has caused lower than expected amounts of LNG to flow into the United States. Strong economic growth in developing nations, a cold winter in Europe and nuclear outages in Japan have contributed to the worldwide demand for LNG. PEC expects continued volatility in the natural gas markets. PEC's forecasted delivered natural gas cost, excluding fixed costs, for the forecasted year ending November 30, 2009, is $10.58 per mmBtu. This amount includes the benefit of natural gas price hedges which are considerably below current market value. The current market price of natural gas delivered to PEC approximates $12.50 per mmBtu, excluding fixed costs. At current market prices, PEC's natural gas hedges will generate approximately $50 million of customer savings during the forecast period.

Effective August 20, 2007, North Carolina Session Law 2007-397 ("Senate Bill 3") provided for the recovery of certain fuel-related costs, including "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions," hereinafter referred to as "reagents," through the fuel factor. Witness Barkley explained that limestone is used by PEC in pollution control devices known as wet scrubbers to remove sulfur dioxide (SO_2). Ammonia and urea are used in catalytic reduction technologies to reduce nitrogen oxides (NO_x). During the period August 20, 2007, through March 31, 2008, PEC's limestone/ammonia/urea costs were $7.2 million. PEC did not incur any lime, dibasic acid, sorbent, or catalyst costs during the test period.

Senate Bill 3 also amended G.S. 62-133.2 to allow electric utilities to recover delivered non-capacity costs, including all related transmission charges, of all power purchases subject to economic dispatch or economic curtailment; the capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; and, except for those costs recoverable pursuant to G.S. 62-133.8(h), the total delivered costs of all purchases of power from renewable energy facilities pursuant to G.S. 62-133.8. Finally, Senate Bill 3 requires the inclusion in fuel and fuel-related costs of the net gains and losses resulting from sales of by-products produced in the generation process to the extent the cost of the inputs leading to the by-product are included in fuel or fuel-related costs. PEC witness Barkley explained that all such purchased power costs and by-product net gains and losses were included in test year expenses and in PEC's forecasted fuel and fuel-related costs. PEC allocated these costs to its customers in the manner required by G.S. 62-133.2(a2). PEC witness Barkley testified that PEC prudently incurred all of its fuel and fuel-related costs in this proceeding, including its reagent and purchased power costs.

Witness Roberts testified that PEC prudently operated and dispatched its generation resources during the test period in order to minimize its fuel costs. He also testified that over 44% of PEC's generation during the test period was provided by its nuclear plants. According to Witness Barkley Exhibit No. 8, the average cost of nuclear fuel burned during the test period equaled $4.78/MWh. This cost is less than 20% of the cost of coal generation and approximately 5% of the cost of natural gas generation.

Regarding power plant performance, witness Roberts testified that two different measures are utilized to evaluate the performance of its generating facilities, the equivalent availability factor and the capacity factor. Equivalent availability factor refers to the percent of a given time a facility was available to operate at full power if needed. It describes how well a facility was operated, even in cases where the unit was used in a load following application. Capacity factor measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based on its maximum dependable capacity.

Regarding the operation of PEC's natural gas and coal fired plants, witness Roberts explained that PEC's combustion turbines averaged a 93.24% equivalent availability and a 5.75% capacity factor for the twelve-month period ending March 31, 2008. These performance indicators are consistent with combustion turbine generation's intended purpose. The generation was almost always available for use, but operated minimally. PEC's intermediate Richmond County combined cycle unit had a 90.43% equivalent availability and a 35.56% capacity factor for the twelve-month period ending March 31, 2008. PEC's intermediate coal fired units had an average equivalent availability factor of 88.93% and a capacity factor of 63.89% for the twelve-month period ending March 31, 2008. He testified that these performance indicators for the intermediate units are indicative of good performance and management. Witness Roberts testified that PEC's fossil base load units had an average equivalent availability of 89.78% and a capacity factor of 73.45% for the twelve-month period ending March 31, 2008. Thus, he concluded the fossil base load units were also well managed and operated.

With regard to the operation of PEC's nuclear generation plants, witness Roberts explained that, for the twelve-month period ending March 31, 2008, the Company's nuclear generation system achieved a net capacity factor of 92.78%. This capacity factor includes nuclear plant refueling outages. In contrast, the North American Electric Reliability Council's ("NERC") five-year average capacity factor for 2002-2006, appropriately weighted for size and type of each plant in PEC's nuclear system, was 87.81%. The Company's nuclear system incurred a .67% forced outage rate during the twelve-month period ending March 31, 2008 compared to the industry average of 4.21% for similar-size nuclear generators. Witness Roberts concluded that these performance indicators reflect good nuclear performance and management for the review period.

Witness Roberts explained that Commission Rule R8-55 provides that a utility shall enjoy a rebuttable presumption of prudent operation of its nuclear facilities if it achieves a system average nuclear capacity factor during the test period that is (a) at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available, as reflected in the most recent NERC Equipment Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available, as reflected in the most recent NERC Equipment Availability Report, appropriately weighted for size and type of plant. Witness Roberts testified that the Company met the standard for prudent operation as set forth in Commission Rule R8-55(i). Public Staff witness Lam verified PEC's test year average capacity factor calculation.

Regarding power purchases to replace PEC owned generation, witness Roberts testified that PEC is constantly reviewing the power markets for purchase opportunities. He explained that PEC purchases power when there is reliable power available that is less expensive than the marginal cost of all available resources to PEC. This review of the power markets is done on an hourly, daily, weekly, and monthly basis. Also, with regard to long-term resource planning, PEC always evaluates purchased power opportunities against self-build options.

Public Staff witnesses Lam testified that he reviewed PEC's fuel and fuel-related costs, baseload power plant performance, and Application. He did not express any concerns in any of these areas.

No other party offered any evidence regarding PEC's fuel and fuel-related costs (including reagent costs), power purchases, or base load performance during the test period. Thus, the Commission finds and concludes that PEC's fuel and fuel-related costs (including reagent costs) and power purchasing practices and costs and the operation of PEC's base load plants were reasonable and prudent during the test period. Based upon the fuel procurement practices report and the evidence in the record, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is contained in the affidavit of Public Staff witness Johnson and the testimony and exhibits of PEC witness Barkley.

PEC witness Barkley explained that Senate Bill 3 added the "total delivered non-capacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility, that are subject to economic dispatch or economic curtailment" to the definition of "fuel-related costs," but that this amendment was not effective until January 1, 2008. Therefore, in calculating fuel expense for the 2007 portion of the test period, PEC used the fuel-to-energy proxy to determine the fuel cost component of purchased power from certain suppliers. PEC has included a representative level of non-capacity purchased power costs in calculating the proposed fuel and fuel-related cost factor for the period December 1, 2008, through November 30, 2009.

In Public Staff witness Johnson's affidavit, she presented the results of an analysis regarding the appropriate fuel-to-energy percentage to be applied to energy costs associated with certain purchases from power marketers and other suppliers who supplied power to PEC during the test year ended March 31, 2008.

Public Staff witness Johnson explained that, during the test year, PEC purchased power from a number of power marketers, as well as from other suppliers who did not provide PEC with the actual fuel costs associated with those purchases. As explained in her affidavit, for the months of April through December 2007, she recommended that the Commission adopt, for purposes of this proceeding, a fuel-to-energy factor of 61% to be applied to purchases from power marketers and to purchases from other sellers that did not provide PEC with actual fuel costs. This recommendation was based on the same underlying analysis used in prior cases for these types of purchases.

As mentioned earlier, beginning in January 2008, in accordance with the provisions of G.S. 62-133.2 as amended by Senate Bill 3, PEC included both fuel and non-fuel purchased power energy costs in its calculation of actual fuel and fuel-related costs for purposes of this proceeding, thus eliminating the need to apply the fuel-to-energy factor. However, for the portion of the test year from April 1, 2007, through December 31, 2007, G.S. 62-133.2 allowed recovery of only the fuel cost component of purchased power. In its Order of June 21, 1996, in Docket No. E-7, Sub 575, the Commission stated that whether a proxy for actual fuel costs associated with power purchases would be acceptable in a future fuel proceeding would depend on "whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available." 86 N.C.U.C. 213, 221 (1996).

For the purpose of calculating a fuel-to-energy percentage to be used to determine the proxy fuel cost in fuel proceedings held in 2008, the Public Staff performed a review of the aggregate fuel component of off-system sales made by PEC and Duke Energy Carolinas, LLC ("Duke"), for the twelve months ended December 31, 2007. As with its most recent review, for the twelve months ended December 31, 2006, the Public Staff did not use the off-system sales for Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") in its analysis. The rationale for excluding DNCP is two-fold. First, of the four counterparties for whom DNCP recorded off-system sales in 2007, DNCP recorded no fuel costs for one and appeared to utilize a "proxy percentage" rather than actual fuel costs to determine the fuel component of total energy for two others. Second, the remaining counterparty was PJM Interconnection, LLC ("PJM"), with whom DNCP participates in complex contractual arrangements associated with DNCP's membership in the PJM Regional Transmission Organization. The fuel costs recorded by DNCP in conjunction with its 2007 off-system sales to PJM equaled exactly 100% of total energy dollars. Because the accounting for these transactions does not reflect what one would expect from a stand-alone arrangement for the off-system sale of energy, and in light of the complex nature of the relationship between DNCP and PJM, none of the transactions would appear to provide meaningful data to the analysis. Therefore, the Public Staff considers it reasonable to exclude these transactions from the determination of the fuel-to-energy percentage accomplished through this analysis.

Despite the removal of DNCP, this analysis is similar overall to that performed by the Public Staff for the 1997 Stipulation addressing the determination of the fuel costs of purchased power (which was applicable to the utilities' 1997 and 1998 fuel proceedings) and the similar 1999 Stipulation filed in Docket No. E-2, Sub 748 (applicable to the 1999, 2000, and 2001 fuel cost proceedings). Similar analyses were performed for the fuel proceedings held in 2002 through 2007. The methodology used for each of the above-mentioned Stipulations and subsequent fuel proceedings has been accepted by the Commission as reasonable for purposes of each fuel case since the beginning of 1997.

The Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for determining the proxy fuel cost as described above. Because the sales made by marketers and other suppliers utilize the same types of generation resources that the utilities use to make their sales, the Public Staff believes that it is reasonable to assume for purposes of these proceedings that the fuel-to-energy percentage inherent in the purchases made by the utilities is similar to the percentage exhibited by the utilities' sales. Additionally, the information used by the Public Staff to determine the off-system sales fuel percentage was derived from the Monthly Fuel Reports filed with the Commission and is, in the opinion of the Public Staff, reasonably reliable. Finally, the Public Staff is unaware of any alternative information currently available concerning the fuel cost component of marketers' sales made to utilities. Therefore, the Public Staff believes that the methodology used in past Stipulations and in the analysis for this proceeding meets the criteria set forth in the 1996 Duke Order for purposes of this proceeding.

As part of its current review, the Public Staff analyzed the available off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 58.40% to 67.68%, as set forth on Johnson Exhibit I. After evaluating all of the data and calculations, the Public Staff concluded that the fuel-to-energy factor to be utilized for purposes of this proceeding should be 61%.

The Commission concludes, as it has in past proceedings, that the methodology underlying the 1997 and 1999 Stipulations and the use of the utilities' own off-system sales to determine the proxy fuel cost for purchases from entities that do not provide actual fuel cost information to the purchasing utility are reasonable and satisfy the requirements set forth in the 1996 Duke fuel case order for purposes of calculating fuel costs incurred through December 31, 2007, in this proceeding. First, the results of applying the methodology can be accepted under G.S. 62-133.2 as it is applicable to purchased power costs incurred prior to January 1, 2008. As Public Staff witness Johnson stated in her affidavit, the sales made by marketers and other relevant suppliers are sourced from the same types of generation resources that the utilities regulated by this Commission use to make their sales. The Commission thus finds it reasonable to assume for purposes of this proceeding that the fuel-to-energy cost percentage exhibited in the utilities' sales is similar to the percentage inherent in the sales made to PEC from the same types of generating resources. Second, the Commission concludes that the information used by parties to derive the fuel percentage is reasonably reliable. According to Public Staff witness Johnson's affidavit, this data was derived from the Monthly Fuel Reports filed by the utilities with the Commission, which are public reports taken from the utilities' financial records and are subject to Commission review. Finally, no party to this proceeding has elicited evidence of any available alternative information concerning the fuel cost component of purchases made from power marketers or other similar sellers of power to PEC. Therefore, the Commission concludes that the methodology underlying the 1997 and 1999 Stipulations used in prior cases meets the criteria set forth in the 1996 PEC fuel case Order, and is reasonable for use in this proceeding as the method of determining the proxy fuel cost for purchased power costs incurred during the 2007 portion of the test period.

Given the fact that the Commission has concluded that the methodology underlying the 1997 and 1999 Stipulations is reasonable for purposes of this proceeding, the question remains as to the appropriate fuel percentage to be used in this case. As part of its current review, the Public

Staff analyzed the off-system sales information in different ways. The Public Staff's analyses resulted in percentages ranging from 58.40% to 67.68%. Based on its analyses, the Public Staff concluded that 61% is an appropriate and reasonable fuel proxy percentage for purposes of this proceeding. PEC accepted the results of the analysis performed by the Public Staff.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use a 61% fuel percentage as the basis for determining the proxy fuel costs for purchases during the test period from power marketers and other suppliers that did not provide actual fuel costs.

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

The evidence for these findings of fact is contained in the testimony and exhibits of PEC witness Barkley and the affidavits of Public Staff witnesses Edwards and Lam.

Witness Barkley testified that Barkley Exhibit No. 5A provided forecasted fuel costs for the year ending November 30, 2009, and the proposed rate design to recover the cost of fuel and fuel-related costs as mandated by G.S. 62.133.2(a2). This exhibit showed total system fuel costs of $1,908,279,468 which consisted of non-capacity related purchased power costs subject to economic dispatch or economic curtailment of $212,525,561; costs of capacity associated with qualifying cogeneration and small power production that are subject to economic dispatch and the fuel and fuel-related costs of renewables as defined by G.S. 62-133.8 of $22,264,529; and other fuel and fuel-related costs of $1,673,489,378. The nuclear capacity factor included in these projections is 94%. PEC allocated non-capacity related purchased power costs subject to economic dispatch or economic curtailment based upon energy usage for the prior calendar year (2007). Costs of capacity associated with qualifying cogeneration and small power production that are subject to economic dispatch and the fuel and fuel-related cost of renewables as defined by G.S. 62.133.7 were allocated based upon peak demand. The peak demand utilized by PEC is the one-hour coincident peak experienced during 2007, which occurred on August 9, 2007, from 4:00 pm to 5:00 pm. The amount of fuel and fuel-related costs allocated to the North Carolina retail jurisdiction was presented on Barkley Exhibit No. 5B. As shown at Barkley Exhibit No. 5B, other fuel and fuel-related costs were allocated to the North Carolina retail jurisdiction based upon forecasted sales. The amount allocated to North Carolina retail jurisdiction was $1,252,013,048 and included non-capacity purchased power costs, qualifying cogeneration capacity and renewable energy costs, and other fuel and fuel-related costs of $139,370,127; $15,539,260; and $1,097,103,661, respectively. No other parties objected to or otherwise challenged PEC's forecasted fuel and fuel-related costs for the rate review period.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

PEC witness Barkley testified that, for the test year ending March 31, 2008, PEC experienced a fuel revenue under-recovery of $114.8 million in its North Carolina retail jurisdiction as shown on line 14 of Barkley Exhibit No. 6. As allowed under R8-55 (d)(3), PEC also included fuel and fuel-related costs incurred through July 31, 2008, in its under-recovery. Witness Barkley testified that, as of July 31, 2008, PEC's fuel and fuel-related costs revenue under-recovery was $191,559,700. This under-recovery was determined by comparing the base fuel factor of 2.060 cents per kWh established by the Commission in Docket No. E-2, Sub 889, to the actual fuel expenses from April 1, 2007, to September 30, 2007, and then comparing the base fuel factor of 2.288 cents per kWh approved by the Commission in Docket No. E-2, Sub 903, to actual fuel expenses from October 1, 2007, to July 31, 2008.

Witness Barkley also included $188,735 of additional fuel expense resulting from the increase in the fuel percentage proxy recommended by Public Staff witness Johnson and interest of $13,314,859 calculated by PEC during the period from April 1, 2007, through July 31, 2008. The Commission approved the collection of interest associated with fuel under-collections in Docket Nos. E-2, Subs 868, 889, and 903.

In making this calculation, witness Barkley explained in his supplemental direct testimony that he made an adjustment of $746,028 to reduce purchased power costs in PEC's deferred fuel balance. In addition, he removed $954,226 of transmission costs that are not recoverable through PEC's fuel and fuel-related recovery clause.

Witness Barkley testified that, in PEC's last general rate case, non-fuel energy costs related to dispatchable economic power purchases of approximately $1.2 million were included in test year expenses. These costs were not defined as fuel costs at the time of the general rate case and were therefore included in base rates. These costs are now included in the definition of fuel and fuel-related costs under Senate Bill 3, specifically G.S. 62.133.2(a1)(4). Therefore, PEC adjusted its deferred fuel account for each month from January 2008 through the implementation of new rates in this proceeding by lowering its deferred fuel account balance due from customers by an amount equal to 0.003 cents per kWh (as calculated on page 1 of Supplemental Barkley Exhibit No. 1) multiplied by the kWh sold to the North Carolina retail jurisdiction to reflect the fact that this amount of purchased power costs is being recovered in base rates. The amount for January through July 2008 of $746,028 is shown on page 1 of Supplemental Barkley Exhibit No. 1.

Going forward, PEC witness Barkley recommended addressing this issue by increasing its base fuel factor to 1.280 cents per kWh rather than the 1.276 cents per kWh that was established in Docket No. E-2, Sub 537 and used in all subsequent fuel proceedings.

Finally, PEC adjusted its under-recovery to remove certain transmission costs associated with operating PEC's system that should not have been included in fuel and fuel-related costs during January through July of 2008. PEC removed $954,226 from the deferred account and will not include these costs in future monthly fuel and fuel-related clause calculations. The total amount proposed for recovery via PEC's EMF in this proceeding was $203,363,040, including the items described above.

Public Staff witness Edwards testified in his affidavit that the Public Staff investigated PEC's under-recovery and concurred in PEC's calculation. He explained that, consistent with the Senate Bill 3 amendments to G.S. 62-133.2, PEC included in its fuel and fuel-related cost recovery calculation in this proceeding reagent costs incurred from August 20, 2007, through July 31, 2008, and certain non-fuel purchased power expenses incurred from January 1, 2008, through July 31, 2008, net of those amounts included in the most recent general rate case (Docket No. E-2, Sub 537).

The Public Staff's investigation of PEC's proposed EMF rider included procedures to evaluate whether PEC properly determined its per-books fuel and fuel-related costs and fuel and fuel-related revenues during the test period. These procedures included review of the Company's filing, prior Commission Orders, the Monthly Fuel Reports filed by the Company, and other Company data provided to the Public Staff. Additionally, the procedures included review of certain specific types of expenditures impacting the Company's test year fuel and fuel-related costs, including nuclear fuel disposal costs, federally mandated payments for decommissioning and decontamination of Department of Energy uranium enrichment facilities, payments to non-utility generators, and purchases of power from suppliers who may or may not have provided the actual fuel costs associated with those purchases. Also, the Public Staff's procedures included review of source documentation of fuel and fuel-related costs for certain selected PEC generation resources as well as source documents for fuel and fuel-related purchased power and transmission costs. For purposes of this particular proceeding, the Public Staff's investigation also included a detailed review of the Sub 537 fuel-related costs proposed by PEC to be included in this proceeding's under-recovery calculation as offsets to fuel-related costs incurred during the test year. The performance of the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as site visits to PEC's offices. The Public Staff generally limited its investigation to costs incurred during the test year. In accordance with G.S. 62-133.2 and Commission Rule R8-55, the Public Staff will review PEC's fuel and fuel-related costs incurred from April through July 2008 in PEC's next annual fuel proceeding.

Witness Edwards explained that, consistent with Public Staff witness Johnson's testimony, PEC applied the marketer factor of 61% to all purchases made prior to January 1, 2008. Beginning in January 2008, in accordance with Senate Bill 3, PEC included fuel and non-fuel energy costs of purchased power in its calculation of actual fuel and fuel-related costs for purposes of this fuel proceeding, thus eliminating the need to apply the 61% factor. In making its under-recovery calculation, PEC adjusted the April through December 2007 fuel cost of purchased power to reflect the 61% factor.

PEC witness Barkley also testified that he had determined that PEC's annual increase in the aggregate amount of the costs identified in subdivisions (4), (5), and (6) of G.S. 62-133.2(a1) does not exceed 2% of its North Carolina retail gross revenues for 2007, as required by G.S. 62-133.2(a2).

No other party offered any evidence regarding PEC's under-recovered fuel and fuel-related costs or the Company's forecasted costs for the projected billing period from December 1, 2008, through November 30, 2009.

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

The evidence for these findings of fact is contained in the testimony and exhibits of PEC witness Barkley and the affidavits of Public Staff witnesses Edwards and Lam.

Prior to enactment of Session Law 2007-397, G.S. 62-133.2(a) required the Commission to apply a "uniform increment or decrement" to electric rates for the recovery of fuel costs, i.e., all customers in all customer classes paid the same fuel rider per-kWh consumed. Section 5 of Session Law 2007-397 removed the word "uniform" from the statute. In the present case, for the first time, PEC proposes to develop individual factors for each rate class such that each class will experience the same percentage increase in its average monthly bill. The overall average monthly bill increase initially proposed by PEC was 13.61% and was calculated by dividing the level of increase shown on Barkley Exhibit No. 5B by the annualized and normalized revenues as shown on Barkley Exhibit No. 5C.

PEC witness Barkley testified that PEC was proposing this new methodology in order to treat all rate classes equitably in recovering its fuel and fuel-related costs. The traditional methodology, i.e., a uniform cents per-kWh of usage, would result in an approximately 18% increase to PEC's large industrial customers. PEC witness Barkley testified that such a large percentage increase could negatively impact industrial operations and could result in job losses, shifts in production to other states or countries, and plant closings. He further testified that PEC's industrial sales have declined every year since 1999. In addition, employment in the industrial segment has declined 30% since 2000. Given the condition of PEC's industrial customers, PEC proposed to allocate this significant cost increase in a manner that amounts to a uniform bill increase of 13.61%, rather than using a uniform per-kWh rate.

In his supplemental testimony, witness Barkley described and supported the Settlement Agreement entered into by PEC, the Public Staff, CIGFUR II, and CUCA, in which these parties agreed to PEC's collecting its deferred fuel balance presented on Revised Barkley Exhibit No. 6 of $203,363,040 over a three-year period. Spreading the recovery of the deferred balance over three years lowers the percentage increase from 13.61% to 9.05%, as shown on Revised Barkley Exhibit No. 5C, Page 1 of 3. This reduces the typical residential customer's monthly bill increase from $13.28 to $8.79. The settling parties agreed that the amounts that PEC is entitled to recover during the rate period December 1, 2008, through November 30, 2009, that will not be recovered until Years Two and Three of the Settlement Agreement will bear interest on the net of tax balance at a rate equal to the five-year United States Treasury Note plus 150 basis points, adjusted quarterly. The Settlement Agreement contains an example of the interest calculations that includes assumptions for interest and income tax rates. The interest and income tax rates in the example will be replaced by the actual rates in effect each quarter.

Based upon witness Barkley's supplemental testimony, the fuel and fuel-related factors proposed by the settling parties are:

Rate Class	Proposed Adjustment	Proposed Factors	Proposed Adjustment with GRT and Reg Fee
Residential	2.070	3.350	2.142
Small General Service	2.139	3.419	2.213
Medium General Service	1.874	3.154	1.939
Large General Service	1.760	3.040	1.821
Lighting	3.039	4.319	3.144

The proposed factors above represent total billing rates per Revised Barkley Exhibit No. 5D, exclusive of the EMF. The proposed adjustment is the difference between the proposed fuel factors and the base fuel factor of 1.280 cents per kWh shown on page 2 of Supplemental Barkley Exhibit No. 1.

PEC calculated the necessary EMF in Barkley Revised Exhibit No. 6. This calculation is based upon the spreading of the cost recovery of PEC's July 31, 2008 deferred fuel and fuel-related costs balance over the three-year period from December 1, 2008, through November 30, 2011. As stated previously, witness Barkley testified that he computed an EMF necessary to collect (1) the July 31, 2008 under-recovery of $191,559,700; (2) $188,735 of additional fuel expense resulting from the increase in the fuel percentage proxy used for vendors that do not provide fuel costs from 58% to 61% as proposed by Public Staff witness Johnson in Docket No. E-7, Sub 847; and (3) $13.3 million of interest accrued through July 31, 2008, pursuant to Commission Orders issued in Docket No. E-2, Subs 868, 889, and 903 and adjustments of $746,028 and $954,226 concerning purchased power costs and transmission costs, respectively. This EMF would remain in effect for twelve months from the effective date of the Commission's Order in this proceeding. The 37,619,054,066 kWh used to calculate the EMF increment represented test year sales to the North Carolina retail jurisdiction adjusted for customer growth and weather normalization. The proposed EMF is 0.180 cents per kWh exclusive of gross receipts tax ("GRT") and regulatory fee. The EMF including GRT and regulatory fee is 0.186 cents per kWh.

Public Staff witness Edwards testified that, if reflected in rates over the 12 months beginning December 1, 2008, the $203,363,040 under-recovery amount, divided by the Company's pro-forma test year North Carolina retail sales of 37,619,054,066 kWh, would result in an EMF increment rider of 0.541 cents per kWh, excluding GRT and regulatory fee. However, as set forth in Barkley's supplemental direct testimony and revised exhibits, PEC has proposed an EMF increment rider of 0.180 cents per kWh, excluding GRT and regulatory fee. This rider is based on PEC's under-recovery amount multiplied by 33.33% and divided by PEC's pro-forma test year North Carolina retail sales of 37,619,054,066 kWh. The Public Staff supports PEC's proposal to recover its total fuel and fuel-related costs using a methodology that results in a uniform percent increase per average monthly bill per rate class, provided that the $203,363,040 total is recovered over a three-year period in accordance with the Settlement Agreement entered into by PEC, the Public Staff, CIGFUR II, and CUCA.

Public Staff witness Lam explained in his affidavit that the total requested dollar increase as shown on Revised Barkley Exhibit No. 5B is $275,371,476, which includes the phased-in recovery of the under-collection of $203,363,040 as of July 31, 2008. He agreed with PEC witness Barkley that this increase is largely attributable to a dramatic increase in coal prices during 2008. Witness Lam testified that, in PEC's initial application, PEC proposed to recover this entire amount through individual factors for each of five rate classes (the General Service Class was separated into three rate groups based on usage characteristics) calculated so that each class would experience the same percentage increase per average monthly bill. He explained that the Public Staff recognizes the significant and disproportionate impact on the industrial class of recovering these increased costs on a uniform cents per kWh basis as well as the need to fairly allocate the rate impact on all customer classes in this period of economic uncertainty, plant closings, and rising unemployment. Therefore, the Public Staff supports PEC's proposed methodology, provided the impact of the cost increase is further moderated by spreading the EMF under-collection of $203,363,040 shown on Revised Barkley Exhibit No. 6 over the upcoming billing period and the next two billing periods.

Witness Lam testified that the EMF components to be approved in the 2009 and 2010 proceedings would include the phased-in recovery of the $203,363,040 under-collection as of July 31, 2008, but would also reflect the under-recovery or over-recovery of fuel costs incurred during the updated test periods in those proceedings. The prospective components would be determined based upon test period costs and other evidence in those proceedings.

In accordance with the Settlement Agreement, witness Lam recommended approval of the following total fuel factors (the sum of the fuel and fuel-related components and EMF component excluding GRT and regulatory fee) consistent with the testimony of PEC witness Barkley effective for the twelve months beginning December 1, 2008:

Rate Class	Total Fuel Factor
Residential	3.530¢/kWh
Small General Service	3.599¢/kWh
Medium General Service	3.334¢/kWh
Large General Service	3.220¢/kWh
Lighting	4.499¢/kWh

The AG did not join in the Settlement Agreement, and the AG argued against PEC's uniform bill increase approach in his brief. First, citing language in Session Law 2007-397, the AG argues that any fuel costs that PEC incurred prior to January 1, 2008, can only be recovered by a traditional, uniform per-kWh increment. Session Law 2007-397 has specific language providing for the effective dates of its various provisions. As for Section 5 (the section that removed the word "uniform" from the fuel statute), Session Law 2007-397 provides that

> [S]ection 5 of this act becomes effective 1 January 2008 provided that (i) the provisions of G.S. 62-133.2, as amended by Section 5 of this act, apply only to

fuel and fuel-related costs incurred on and after 1 January 2008 regardless of the test period established by the Utilities Commission.

PEC states in its proposed order that, "by the plain words of the statute, effective January 1, 2008, the Commission is no longer restricted to using a uniform rate applicable to all classes to recover a utility's fuel and fuel-related costs regardless of when the costs were incurred." The Commission believes that the plain words of the statute provide otherwise. Alternatively, PEC argues, "assuming that this additional rate design flexibility only applies to costs incurred on and after January 1, 2008, (the effective date of this change in G.S. 62-133.2(a)), PEC's proposed EMF is to be recovered on a uniform rate per kWh basis." The Commission agrees with this alternative argument. Revised Barkley Exhibits No. 5D and 6 demonstrate that the EMF was indeed calculated on a cents-per-kWh basis and that each of the non-uniform fuel factors proposed for the different rate classes includes a uniform EMF factor of 0.180 cents/kWh.

Second, the AG argues that PEC's proposal for a uniform bill increase shifts $38.7 million from industrial and medium general service customers to residential, small general service, and lighting customers and that PEC presented insufficient evidence to support such a shift in the allocation of costs. The AG concedes that the Commission can consider the economic impact of rates on industrial customers, but argues that the Commission should also consider other factors and that PEC presented no evidence as to the other factors that should be considered.

The Commission rejects the AG's argument. The North Carolina Supreme Court has addressed the factors that the Commission may consider in designing rates. In addition to the utility's cost of service, the Commission may consider factors such as value of service, the quantity of service used, the time of use, the manner of use, the equipment that must be provided and maintained, competitive conditions, and consumption characteristics. State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223 (2000); State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 323 N.C. 238 (1988). In State ex rel. Utilities Commission v. Public Staff-North Carolina Utilities Commission, 323 N.C. 481 (1988), the Supreme Court upheld a rate design with different rates of return for different customer classes which the Commission had adopted after considering several non-cost factors. Among these factors, the Commission considered historic rate differentials between customer classes, the relative percent increases that would occur if all rate classes were required to pay the same rate of return, and the "economic and political factors which are inherent in the ratemaking process." Id. at 502. Similarly, in State ex rel. Utilities Commission v. Carolina Utility Customers Association, 328 N.C. 37 (1991), the Supreme Court upheld a Commission decision that, when all relevant factors are weighed and considered, a lower rate of return for the residential class than for other customer classes was not unreasonably discriminatory. In this case, although PEC did not present evidence as to all of the factors that might appropriately be considered, PEC did present evidence as to some of these factors. The Commission concludes that the issue therefore becomes a matter of the weight and credibility of the evidence. In this case, the impact that a uniform rate increment would have on PEC's industrial class, in conjunction with the potential job losses and shifts in production to other states and countries, constitute valid factors properly considered by the Commission in establishing PEC's fuel and fuel-related costs rates, and the Commission finds these factors persuasive. After weighing the evidence, the Commission concludes that, in this case, PEC's proposed methodology is just and reasonable and not unreasonably discriminatory.

No other party presented evidence in opposition to spreading the recovery of the deferred fuel balance over the period December 1, 2009, through November 30, 2011, at the interest rate proposed. The AG "does not oppose spreading the impact of a uniform per kWh fuel rider over the next three years in order to avoid rate shock."

The Commission finds and concludes that the rates proposed by the settling parties are just and reasonable and should be approved for purposes of this proceeding. In doing so, the Commission has adopted the uniform bill increase methodology and the recovery of PEC's under-recovered fuel costs as described in Paragraph Nos. 1 and 2 of the Settlement Agreement for the limited purpose of setting rates in this proceeding.

Paragraph No. 3 of the Settlement Agreement would allow any member of CIGFUR II or CUCA to elect to pay their entire pro rata share of the July 31, 2008 deferred fuel cost balance during the rate review period December 1, 2008, through November 30, 2009, and thereby avoid paying any interest on the deferred balance as it exists on December 1, 2009. After carefully examining the record concerning this provision, the Commission concludes that large industrial customers will already receive the benefit of the uniform bill increase methodology approved herein, that there is insufficient evidence to persuade the Commission that Paragraph No. 3 is just and reasonable and not unreasonably discriminatory, and that Paragraph No. 3 would present significant tariff administration issues. Therefore, the Commission will not approve Paragraph No. 3 of the Settlement Agreement. With respect to the other Paragraphs and provisions of the Settlement Agreement, the Commission will address any related issues as they arise in future proceedings.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after December 1, 2008, PEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates approved in Docket No. E-2, Sub 537 as adjusted in this proceeding to 1.280¢/kWh by an amount equal to 2.070¢/kWh for the Residential class, 2.139¢/kWh for the Small General Service class, 1.874¢/kWh for the Medium General Service class, 1.760¢/kWh for the Large General Service class, and 3.039¢/kWh for the Lighting class (excluding gross receipts tax and regulatory fee) and, further, that PEC shall adjust the resultant approved fuel and fuel-related costs by an increment of 0.180¢/kWh (excluding gross receipts tax and regulatory fee) for the EMF increment. The EMF increment is to remain in effect for service rendered through November 30, 2009;

2. That PEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order; and

3. That PEC shall work with the Public Staff to prepare a joint Notice to Customers giving notice of the rate changes ordered by the Commission in Docket No. E-2, Subs 929, 930,

and 931, and PEC shall file such notice for Commission approval within 10 days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of November, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr111408.01

DOCKET NO. E-7, SUB 847

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC Pursuant	)	ORDER APPROVING
to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and	)	FUEL CHARGE
Fuel Related Cost Adjustments for Electric Utilities -2008	)	ADJUSTMENT

HEARD: Thursday, June 5, 2008, at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper III, Presiding, Chairman Edward S. Finley, Jr., Commissioner Robert V. Owens, Jr., Commissioner Sam J. Ervin IV, and Commissioner Lorinzo L. Joyner

APPEARANCES:

For Duke Energy Carolinas, LLC:

Lara Simmons Nichols, Associate General Counsel, Duke Energy Corporation, Post Office Box 1244, Charlotte, North Carolina 28201-1244

and

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

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Len Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the Carolina Industrial Group for Fair Utility Rates III:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602

BY THE COMMISSION: On March 12, 2008, Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company"), filed an Application and accompanying testimony and exhibits pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel and fuel-related charge adjustments for electric utilities. The Company's Application also requested that the Commission extend the current Experience Modification Factor ("EMF") approved in Docket No. E-7, Sub 825, for an additional two months through August 31, 2008.

On March 18, 2008, the Carolina Industrial Group for Fair Utility Rates III ("CIGFUR III") filed a petition to intervene. On March 20, 2008, the Carolina Utility Customers Association, Inc. ("CUCA") filed a petition to intervene. The Commission allowed the interventions of CIGFUR and CUCA on March 24, 2008, and March 26, 2008, respectively. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e). On March 25, 2008, Roy Cooper, Attorney General, filed a notice of intervention. The intervention of the Attorney General is recognized pursuant to G.S. 62-20.

On March 19, 2008, the Commission issued an Order Scheduling Hearing and Allowing Comments on Motion to Continue EMF.

Comments on Duke Energy Carolinas' proposal to extend its current EMF were received by the Commission on April 4, 2008, from the Company, the Attorney General and the Public Staff. On April 23, 2008, the Commission issued its Order Ruling on Motion to Continue EMF, authorizing Duke Energy Carolinas to make a tariff filing extending its current EMF through August 31, 2008. The Company filed its revised Fuel Cost Adjustment Rider tariff on May 1, 2008.

On May 22, 2008, Duke Energy Carolinas filed the supplemental testimony and exhibits of Jane L. McManeus. On May 23, 2008, the Public Staff filed a notice of affidavits and the affidavits of Thomas S. Lam and Sonja R. Johnson. On June 3, 2008, the Commission issued an Order excusing the appearances of Company witnesses Roebel, Geer and Jamil at the hearing.

On June 5, 2008, Duke Energy Carolinas filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as scheduled on June 5, 2008. The prefiled testimony and exhibits of Company witnesses M. Elliott Batson, Director, Coal Procurement; John J. Roebel, Senior Vice President, Engineering and Technical Services; Dhiaa M. Jamil, Senior Vice

President, Nuclear Support; and Thomas C. Geer, Vice President of Nuclear Engineering, were received into evidence and Jane L. McManeus, Director, Rates, presented direct testimony on behalf of the Company. The Commission admitted into evidence the affidavits of Public Staff witnesses Thomas S. Lam, Utilities Engineer, Electric Division, and Sonja R. Johnson, Staff Accountant, Accounting Division. No other party presented witnesses and no public witnesses appeared at the hearing.

After the hearing, the parties filed briefs and proposed orders on July 9, 2008, as allowed by the Commission.

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

FINDINGS OF FACT

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

2. The test period for purposes of this proceeding is the 12-month period ended December 31, 2007.

3. Duke Energy Carolinas' fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

4. The test period per book system sales are 81,118,059 MWh.

5. The test period per book system generation is 91,873,575 MWh and is categorized as follows:

Generation Type	MWh
Coal	47,404,367
Oil and Gas	727,222
Light Off	-
Nuclear	40,486,430
Hydro	993,984
Net Pumped Storage	(902,742)
Purchased Power	2,341,090
Catawba Interchange	657,024
Other Interchange	166,200
Total Generation	91,873,575

6. The nuclear capacity factor appropriate for use in this proceeding is 92%.

7. The adjusted test period system sales for use in this proceeding, including those related to Duke Energy Carolinas' Nantahala Area, are 81,189,090 MWh.

8. The adjusted test period system generation for use in this proceeding, including that of Duke Energy Carolinas' Nantahala Area, is 90,790,708 MWh and is categorized as follows:

Generation Type	MWh
Coal	45,563,900
Oil and Gas	495,143
Light Off	-
Nuclear	41,602,377
Hydro	1,644,346
Net Pumped Storage	(856,148)
Purchased Power	2,341,090
Total Generation	90,790,708

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

A. The coal fuel price is \$31.96/MWh.
B. The oil and gas fuel price is \$97.82/MWh.
C. The appropriate Light Off fuel expense is \$12,640,000.
D. The appropriate ammonia, limestone, urea and dibasic acid (collectively "Reagents") expense is \$33,397,000.
E. The appropriate net proceeds on sale of by-products are (\$2,218,000).
F. The total nuclear fuel price is \$4.83/MWh.
G. The nuclear fuel price for Catawba generation is \$4.71/MWh.
H. The non-capacity purchased power and other purchased power fuel price is \$55.67/MWh.
I. The adjusted level of fuel and fuel-related credits associated with intersystem sales is \$159,369,000.

10. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 61% of the energy portion of the purchase price is reasonable for purposes of determining the Company's EMF in this proceeding.

11. The adjusted test period system fuel and fuel-related costs for use in this proceeding is \$1,720,316,000. Consistent with G.S. 62-133.2(a3), the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs and renewable energy costs does not exceed two percent of Duke Energy Carolinas' total North Carolina jurisdictional gross revenues for 2007.

12. The proper composite fuel and fuel-related costs factor for this proceeding is 2.1189¢/kWh, excluding gross receipts tax and regulatory fee. Consistent with the cost allocation requirements of G.S. 62-133.2(a2)(1), the proper fuel and fuel-related cost factors for

the Company's customer classes are 2.1185¢/kWh for the Residential class, 2.1182¢/kWh for the General Service/Lighting class, and 2.1205¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee.[1]

13. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection was $32,033,000, which includes an ($11,059,000) adjustment for continuing the EMF factor of 0.1037¢/kWh for July and August 2008. The pro forma North Carolina jurisdictional sales are 55,014,640 MWh.

14. The Company's EMF is an increment of 0.0582¢/kWh, excluding gross receipts tax and regulatory fee.

15. The final net fuel and fuel-related cost factors to be billed to Duke Energy Carolinas' North Carolina retail customers during the 2008-2009 fuel clause billing period are 2.1767¢/kWh for the Residential class, 2.1764¢/kWh for the General Service/Lighting class, and 2.1787¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee, consisting of the prospective fuel factors of 2.1185¢/kWh, 2.1182¢/kWh, and 2.1205¢/kWh respectively for the Residential, General Service/Lighting, and Industrial classes and the EMF increment of 0.0582¢/kWh.

16. The Commission's *Order Approving Stipulation and Deciding Non-Settled Issues* ("Rate Order") issued on December 20, 2007 in the Company's last general rate case (Docket No. E-7, Sub 828), approved the transition of the Company's Nantahala Area residential customers to Duke Energy Carolinas' rates and the transition of the Nantahala Area non-residential customers from the Nantahala Purchased Power Rider CP to the Company's fuel and fuel-related cost factors. The Rate Order had the effect of terminating the Nantahala Interconnection Agreement for retail regulatory purposes. The balance of the Energy Bank established under the Nantahala Interconnection Agreement at December 31, 2007 is $11,825,036.

17. It is appropriate for Duke Energy Carolinas to offset the Energy Bank balance with (a) the over-recovery balance at December 31, 2007 resulting from the Rider CP factor approved in Docket No. E-7, Sub 833; (b) the over-recovery balance of purchased power costs experienced from August 2007 through December 2007; and (c) the balance of unclaimed refunds arising out of Docket Nos. E-13, Subs 29, 35 and 44. The Energy Bank balance at December 31, 2007, net of these three items, is $7,414,854. It will also be appropriate to reduce the Energy Bank balance by the total amount billed to Nantahala Area customers through the North Carolina retail EMF component of the fuel and fuel-related costs factor from January 1, 2008 through August 31, 2009. This amount is estimated to be $1.4 million.

18. It is appropriate for Duke Energy Carolinas to institute an annual rider that collects an additional two percent of revenues from its Nantahala Area customers in order to

[1] Duke Energy Carolinas proposed fuel and fuel-related costs factors excluding gross receipts tax. The Public Staff testified as to the factors with and without gross receipts tax. However, it is appropriate for the rates schedules to reflect both gross receipts tax and the regulatory fee.

collect the net unrecovered Energy Bank balance. The proper Nantahala Area Customer Rider for the 2008-2009 billing period is 0.1539¢/kWh, excluding gross receipts tax and regulatory fee.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel and fuel-related charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending December 31st as the test period for Duke Energy Carolinas. The Company's filing was based on the 12 months ended December 31, 2007. In its *Order Adopting Final Rules* issued on February 29, 2008, in Docket No. E-100, Sub 113, the Commission amended Commission Rule R8-55 to move Duke Energy Carolinas' hearing date from the first Tuesday in May to the first Tuesday in June. The amendments also changed the deadline for filing the information required under Rule R8-55 so that the filing must be made at least 90 days prior to the hearing and changed the effective date of any rate change resulting from such a proceeding to no later than 180 days from the filing date in this proceeding, which makes any rate change resulting from the Commission's decision in this proceeding effective as of September 1, 2008.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, in July 2004 and were in effect throughout the 12 months ending December 31, 2007. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is found in the testimony of Company witnesses Batson, Roebel and Geer.

Duke Energy Carolinas witness Batson described the Company's fossil fuel procurement practices. These practices include establishing appropriate inventory requirements, regular requests for proposals ("RFPs") and bid evaluation, balancing of long-term contract and spot purchases, staggering contract expiration dates, pursuing contract extension options, maintaining a well-diversified coal supplier base, and actively monitoring supplier and railroad performance.

Further, witness Batson testified that Duke Energy Carolinas continues to maintain a comprehensive coal procurement strategy that has proven successful over the last several years in limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. He stated that the Company demonstrated the flexibility of its strategy during 2007 by responding to market conditions that led to spot prices that were significantly lower than contract prices offered for 2008. Throughout 2007, Duke Energy

Carolinas purchased spot coal at these lower prices and inventoried it for future use. Witness Batson stated that these efforts to maximize lower-cost coal inventories will result in lower overall costs for 2008, and that these opportunities will continue to be monitored going forward.

Witness Batson testified that the Company has continued to evaluate coal supply delivered into the Carolinas from all domestic and international sources by issuing two or three requests for proposals per year as well as staying abreast of market conditions on a daily basis through reviews of various market analyses, frequent discussions with suppliers and constant monitoring of published market prices. However, witness Batson stated that changes in the coal markets signal the emergence of a "Btu market" in which heat content, rather than other qualities, is the primary price driver. These changes reduce the opportunities for achieving savings through sourcing coal from different regions.

Witness Batson testified that other aspects of Duke Energy Carolinas' procurement strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations such that the Company is not faced with price changes for a significant percentage of its purchases at any one time and pursuing contract extension options that provide flexibility to extend terms within some price collar. Witness Batson explained that the Company has developed a diversified coal supplier base such that the largest single supplier is expected to represent approximately 15% of total coal purchases in 2008. Lastly, witness Batson stated that actively monitoring supplier and railroad performance in 2008 and 2009 will be critically important to protect a supply portfolio that is projected to be more than $500 million below market for 2008 based on February, 2008 market prices.

North Carolina Session Law 2007-397 (Senate Bill 3) added the recovery of certain fuel-related costs, including "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions," referred to by Duke Energy Carolinas' witnesses as "Reagents," through the fuel factor. Company witnesses Batson and Roebel described Duke Energy Carolinas' procurement practices for these Reagents. Witness Batson explained that there are many similarities between limestone and coal, thereby leading to the decision to group these bulk commodities within the same procurement function. Limestone, like coal, is delivered by rail and requires extensive logistical support to ensure proper delivery. The required volume of limestone varies based on the sulfur content of coal; therefore, close coordination and planning between the procurement of the two commodities is necessary. Additionally witness Batson stated that inventory management of limestone is very similar to coal, requiring frequent review of limestone use, deliveries and total inventory. Witness Roebel testified that the Company's objective in procuring these environmental Reagents is to provide its coal-fired generating stations with the most effective total cost solution needed to permit the operation of these units by understanding the technical capabilities of the equipment, assessing Reagent input and by-product output over the long term, assessing and understanding the various Reagent and by-product markets, and looking for leverage opportunities with the Reagent purchase and by-product sales contracts between the Company's coal-fired stations and Duke Energy's Midwest operations. Witness Roebel explained that technical and sourcing teams have been established to accomplish these objectives. These teams have developed action plans for the short term, including the review and refinement of transportation methods and consolidation of contracts, as well as strategies for long term.

Company witness Geer testified as to Duke Energy Carolinas' nuclear fuel procurement practices. These practices involve computing near and long-term consumption forecasts, establishing target inventory levels, projecting required annual fuel purchases, qualifying suppliers, requesting proposals, negotiating a portfolio of spot and long-term contracts from diverse sources of supply and monitoring deliveries for each of the components of nuclear fuel: uranium, conversion, enrichment, and fabrication.

Further, witness Geer testified that Duke Energy Carolinas relies extensively on long-term contracts to cover the largest portion of its forward requirements in the four stages of the nuclear fuel cycle. By staggering long-term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different time periods, which has the effect of reducing the Company's exposure to price volatility. Witness Geer noted that successful implementation of this strategy depends on the willingness of fuel suppliers to offer certain pricing mechanisms under long-term contracts, such as fixed prices, base escalated prices, or caps on market index prices. He also testified to the rise in uranium spot market prices in the previous test period and in the first half of this test period, and explained that, as a result of this increase, the Company found that uranium suppliers were reluctant to offer these pricing mechanisms. Instead, suppliers were offering contracts with delivery prices tied to future market prices with no ceiling and with a floor price equal to current market prices. Witness Geer testified that, as a result of this shift, the Company had adjusted its strategy by purchasing uranium in the spot market and holding it to meet future requirements. He noted that uranium suppliers are beginning to offer more reasonable pricing terms under long-term contracts, which has allowed Duke Energy Carolinas to obtain supplies under such contracts again.

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

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

The evidence for these findings of fact is found in the testimony of Company witnesses McManeus, Roebel and Jamil and the affidavit of Public Staff witness Lam.

Company witness McManeus testified that the test period per book system sales were 81,118,059 MWh and that the test period per book system generation was 91,873,575 MWh. The test period per book generation is categorized as follows:

Generation Type	MWh
Coal	47,404,367
Oil and Gas	727,222
Light Off	-
Nuclear	40,486,430
Hydro	993,984
Net Pumped Storage	(902,742)

Purchased Power	2,341,090
Catawba Interchange	657,024
Other Interchange	166,200
Total Generation	91,873,575

Witness McManeus explained that, in the Rate Order, the Commission approved the terms of the Agreement and Stipulation of Partial Settlement filed by the stipulating parties on October 5, 2007 ("Stipulation"). The Stipulation provided for the transition of the Company's Nantahala Area residential customers to Duke Energy Carolinas' residential rates. For non-residential rates, the Stipulation provides that the non-fuel component of Rider CP will be frozen, that Nantahala non-residential customers will migrate to the Duke Energy Carolinas fuel charge adjustment rider, and that such rates will be closed to new customers. Further, the Stipulation provides for the consolidation of all North Carolina jurisdictional reporting and accounting for Duke Energy Carolinas and Nantahala into that of Duke Energy Carolinas. This transition began on January 1, 2008. As such, witness McManeus stated that, for this proceeding, the Nantahala Area generation and sales are excluded from the calculation of the 2007 test period fuel and fuel-related expenses, and Nantahala Area sales are treated as off-system sales. However, for purposes of calculating the proposed fuel and fuel-related costs factor, the Nantahala Area generation and sales are integrated with Duke Energy Carolinas.

Company witnesses Roebel and Jamil testified as to the operation and performance during the test period of the Company's (1) fossil-fueled and hydroelectric generating facilities and (2) nuclear generation facilities, respectively. Witness Roebel testified that Duke Energy Carolinas operates a diverse mix of units that allow the Company to meet its continuously changing customer load pattern in a logical and cost-effective manner. He testified that, during the test period, the fossil-fuel generating plants operated efficiently and reliably and that the heat rate for the coal units was 9,639 BTU/kWh. Achievement of this heat rate continues Duke Energy Carolinas' consistent track record of operating some of the most efficient fossil-fired units in the country. Witness Roebel further testified as to the various performance indicators that are indicative of the solid performance and good operation and management of Duke Energy Carolinas' fossil and hydroelectric fleet during the test period, particularly in light of the number of scheduled outage days required for the installation of environmental controls and the impact of the extreme drought conditions experienced in the Company's service territory.

Witness Roebel testified regarding these extreme drought conditions and their impact on the Company's hydroelectric and fossil-fueled generation. During 2007, rainfall in Duke Energy Carolinas' service territory was more than a foot and a half below the long-term annual average, and stream flows dropped to record lows, making 2007 the driest year for North Carolina and the fifth driest year for South Carolina in 113 years. Witness Roebel stated that U.S. Drought Monitor maps have labeled most of Duke Energy Carolinas' service territory as experiencing "exceptional drought conditions," the most severe category.

Witness Roebel testified that this unexpected severe rain shortfall and the resulting low stream flow conditions affected the availability of conventional hydroelectric units and resulted in cooling water thermal limitations at coal-fired facilities. As a result of these exceptional conditions, the Company modified its operations to account for the adverse impact of the prolonged drought. Duke Energy Carolinas began reducing the use of its hydroelectric generating units in April, 2007, and the reduced use of these units continued throughout the balance of the year. During the period from April through December 2007, Duke Energy Carolinas' conventional hydroelectric plants were utilized 67% less often than was typical for the same time period during the previous four years. This action conserved water that is essential to the operation of Duke Energy Carolinas' nuclear and fossil generating assets. The Company voluntarily complied with the minimum flows and the low flow protocol ("LIP") contained in its proposed Federal Energy Regulatory Commission license for the Catawba-Wateree Hydroelectric Project. The LIP was developed on the premise that all parties with interests in water quantity in the Catawba-Wateree basin share the responsibility to establish priorities and to conserve the limited water supply. Such action provides benefits to the Company in that the LIP requires that municipalities withdrawing water from the basin implement mandatory water conservation efforts.

Witness Roebel further explained that the wastewater discharge permits governing the operation of Duke Energy Carolinas' fossil-fueled generation contain limits on the temperature of water discharged from the stations into the bodies of water upon which these stations are located. During periods of low water flow and high ambient temperatures, the temperature of cooling water withdrawn and taken into these stations is elevated, requiring the stations, in some instances, to reduce operations to prevent heating the cooling water to levels that would violate permit limits. Witness Roebel stated that these conditions were most prevalent in August and September 2007. The largest and most efficient combustion turbines were called upon to meet customer demand during these occurrences. In addition, witness Roebel testified that the Company purchased energy in 2007 to manage these environmental constraints and to reduce output during off-peak periods in order to preserve reservoir levels.

Commission Rule R8-55(c)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Council ("NERC") Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. Witness Jamil testified that the test period included four refueling outages and that, during this period, Duke Energy Carolinas achieved a system average nuclear capacity factor of 92.36%, the third highest in fleet history. He testified that the most recent (2002-2006) NERC five-year average nuclear capacity factor for pressurized water reactor units is 89%. The affidavit of Public Staff witness Lam also included this information. Witness Jamil recommended the use of a nuclear capacity factor of 92% for purposes of setting the fuel rate in this proceeding. This proposed nuclear capacity factor was based on the operational history of the Company's nuclear units and the number of outage days scheduled for the billing period.

By recommending Commission approval of Duke Energy Carolinas' proposed fuel factor, Public Staff witness Lam implicitly agreed with the Company's per books sales and generation levels of 81,118,059 MWh and 91,873,575 MWh, respectively, as well as the Company's recommended nuclear capacity factor of 92%. No other party contested these amounts.

Based upon the agreement of the Company and the Public Staff as to the appropriate levels of per book system MWh generation and sales, and noting the absence of evidence to the contrary, the Commission concludes that the levels of per book system sales of 81,118,059 MWh and per book system generation of 91,873,575 MWh are reasonable and appropriate for use in this proceeding.

Based upon the requirements of Commission Rule R8-55(c)(1), the historical and reasonably expected performance of the Duke Energy Carolinas system, and the agreement of the Public Staff, the Commission concludes that the 92% nuclear capacity factor and its associated generation of 41,602,377 MWh, excluding the Catawba Joint Owners' portion of said generation, proposed by Duke Energy Carolinas are reasonable and appropriate for determining the appropriate fuel costs for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 7-8

The evidence for these findings of fact is found in the testimony of Company witnesses McManeus and Roebel and the affidavit of Public Staff witness Lam.

Witness McManeus made adjustments of 71,031 MWh and (1,082,867) MWh to per book system sales and generation, respectively, for adjustments to normalize for weather, customer growth, the transition of the Nantahala Area customers to Duke Energy Carolinas rates, and line losses/Company use, based on a 92% normalized system nuclear capacity factor. The adjustment related to the transition of the Nantahala Area customers to Duke Energy Carolinas' rate schedules is accomplished by including sales to Nantahala Area customers in normalized kWh sales and by including Nantahala Area hydroelectric generation in the adjusted generation. Further, witness McManeus adjusted nuclear generation to reflect the planned acquisition of Saluda River's ownership interest in Unit 1 of the Catawba Nuclear Station, which will increase Duke Energy Carolinas' ownership interest from 12.5% to 19.35%. Based upon the severe drought in the Company's service territory and its impact on conventional hydroelectric generation, witness McManeus based projected conventional hydroelectric generation for September through December 2008 using test period actual generation to reflect the expected continuation of these abnormal drought conditions. Witness Roebel testified that the Company has and continues to work collaboratively with water users and state and federal agencies to preserve water in its reservoirs. However, based upon current drought projections, Duke Energy Carolinas anticipates that the availability of its hydroelectric generation during 2008 will be consistent with the reduced output experienced during 2007. Thus, witness McManeus calculated an adjusted system sales level of 81,189,090 MWh and an adjusted system generation level of 90,790,708 MWh.

By recommending Commission approval of Duke Energy Carolinas' proposed fuel factor, Public Staff witness Lam implicitly accepted witness McManeus' adjusted sales and generation levels of 81,189,090 MWh and 90,790,708 MWh, respectively. No party contested the Company's adjustments for weather, customer growth, Nantahala customers, line losses/Company use, nuclear generation or hydroelectric generation.

The Commission concludes, after finding a system nuclear capacity factor of 92% to be reasonable and appropriate in Finding of Fact No. 6, that the adjustment to per book system generation of (1,082,867) MWh and the resulting adjusted test period system generation level of 90,790,708 MWh are both reasonable and appropriate for purposes of this proceeding. Total adjusted generation is categorized as follows:

Generation Type	MWh
Coal	45,563,900
Oil and Gas	495,143
Light Off	-
Nuclear	41,602,377
Hydro	1,644,346
Net Pumped Storage	(856,148)
Purchased Power	2,341,090
Total Generation	90,790,708

The Commission also finds the adjusted sales level of 81,189,090 MWh to be reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is found in the testimony and exhibits of Company witnesses Batson, McManeus, Roebel, and Geer and the affidavit of Public Staff witness Lam.

In 2007, Senate Bill 3 amended G.S. 62-133.2 by adding a definition of "fuel and fuel-related costs" recoverable through the fuel charge adjustment in subsection (a1) as follows:

(1) The cost of fuel burned.
(2) The cost of fuel transportation.
(3) The cost of ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions [referred to below as "Reagents"]
(4) The total delivered non-capacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility, that are subject to economic dispatch or economic curtailment [referred to below as "Non-Capacity Purchased Power costs"].
(5) The capacity costs associated with all purchases of electric power from qualifying cogeneration facilities and qualifying small power production facilities, as defined in 16 U.S.C. § 796, that are subject to economic dispatch by the electric public utility [referred to below as "QF Capacity costs"].
(6) Except for those costs recovered pursuant to G.S. 62-133.7(h), the total delivered costs of all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.7 or to comply with any federal mandate that is similar to the requirements of subsections (b), (c), (d), (e) and (f) of G.S. 62-133.7 [referred to below as "Renewable Energy costs"].
(7) The fuel cost component of other purchased power.

(8) Cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of fuel and other fuel-related cost components [referred to below as "Fuel Sales net gains or losses"].

(9) Cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs [referred to below as "By-Product Sales net gains or losses"].

The amendment to add Reagent costs as "fuel-related costs" recoverable through the fuel and fuel-related cost charge adjustment was effective August 20, 2007. Witness McManeus testified that the Company's Reagent costs from this date through December 31, 2007, are included in the calculation of incurred fuel expense and in calculating the under-recovery for this proceeding. The addition of items (4), (5), (6), (8) and (9) above to the definition of "fuel-related costs" became effective on January 1, 2008. As such, witness McManeus explained that these costs are not included in calculating fuel expense for the test period. However, Duke Energy Carolinas has included a representative level of Reagent costs, Non-Capacity Purchased Power costs and By-Product sales net gains or losses in calculating the proposed fuel and fuel-related cost factor for the period September 1, 2008 through August 31, 2009. Witness McManeus stated that the Company does not anticipate incurring material costs or gains associated with QF Capacity, Renewable Energy or Fuel Sales net gains or losses during the billing period.

Duke Energy Carolinas' last general rate case was based upon a test period consisting of the twelve months ending December 31, 2006, and was decided on December 20, 2007. In its *Order Approving Stipulation and Deciding Non-Settled Issues* in Docket No. E-7, Sub 828 ("Rate Order"), the Commission identified the North Carolina Retail amounts included in the test period expenses that would constitute fuel-related costs upon the effective dates of Senate Bill 3 for purposes of addressing these costs in future proceedings. In this proceeding, witness McManeus proposed an adjustment of these amounts in order to: (a) reflect the recovery of certain fuel-related costs though off-system sales; (b) correct a calculation error in the amount of transmission charges included in the level of Non-Capacity Purchased Power costs submitted to the Commission in Docket No. E-7, Sub 828; (c) include non-capacity purchased power costs related to energy imbalance and generation imbalance purchases; and (d) subtract non-capacity purchased power costs related to emergency purchases. Witness McManeus explained that it is necessary to revise the level of non-capacity purchased power under G.S. 62-133.2(a1)(4) stated in the Rate Order in order to capture all non-capacity costs associated with economic purchases. Witness McManeus used these revised expenses to calculate the adjusted base fuel and fuel-related costs factor. As adjusted, this amount is used to calculate the proposed factor and proposed EMF.

In response to questions from the Commission, witness McManeus stated that the amendments in Senate Bill 3 to G.S. 62-133.2(a1) are projected to result in approximately $37 million in additional expenses recovered through the fuel clause for the 2008-2009 billing period.

Company witness Batson testified concerning Duke Energy Carolinas' fossil fuel costs during the test year and changes expected in 2008 and 2009. Witness Batson testified that the Company's delivered cost of coal during the test period remained constant between 2006 and 2007, and that these prices were consistent with the projections used by the Company in developing the fuel factor billed during the 2007-2008 billing period. Witness Batson explained that this result is due to three factors which existed during the two-year 2006-2007 period: (1) stable coal markets and prices; (2) a significant percentage of coal requirements supplied under fixed price contracts; and (3) relatively consistent transportation costs.

Witness Batson testified that, at the time his direct testimony was pre-filed, market prices for Central Appalachia coal to be delivered in 2008 and 2009 were at an all-time high. The market increased from the mid $40s per ton in the summer of 2007 to the low to mid $90s per ton by February, 2008. He explained that this dramatic increase in coal prices stemmed from changes in global coal market conditions, particularly recent unanticipated world coal supply disruptions along with increasing world coal demand, that have dramatically increased the demand faced by all United States coal supply regions. These supply disruptions include transportation-related coal shortages in China, extreme flooding and port delays in Australia, and power shortages in South Africa. Witness Batson stated that many of the recent world supply disruptions will eventually be eliminated; however, significantly increasing coal demand in Asia could continue to impact United States coal markets if coal production in Pacific Rim countries does not increase. Witness Batson testified that, after a period of declining and stable Eastern coal prices over the last two years, all United States coal markets, and in particular the Eastern United States Appalachian coal markets, have been significantly impacted.

Additionally, witness Batson testified that mining operations continue to face upward cost pressures due to increasing petroleum and steel costs, growing demand for labor, declining mining productivity, and more stringent mining safety regulations. He further stated that another important factor affecting coal markets is that the supply of coal in the Eastern United States is largely inelastic, so that higher market prices do not always lead to vastly increased rates of production. The primary reasons for this limited supply response are the stringent environmental regulations and lengthy permitting requirements affecting coal production and very significant economic barriers to entry.

Given the Company's expectation that that coal market fundamentals would likely cause upward pressure on market conditions and prices over the long term, witness Batson testified that Duke Energy Carolinas contracted for significant amounts of its 2007 through 2009 coal supply requirements to reduce the impact of increasing coal market prices. He testified that, although Eastern coal prices are at an all-time high, these market prices will have limited impact on the Company's 2008 fuel costs because 95% of projected coal needs have been purchased or contracted for at prices well below current market prices. Based upon the prices for existing coal purchase commitments and the current projected market prices for coal requirements in 2008 that have not yet been purchased, Duke Energy Carolinas projects that it will maintain the same average coal price over the 2006 through 2008 period.

Witness Batson stated that, during 2007, coal producers were unwilling to contract for terms longer than one to two years. The Company's average cost of coal will start to increase in

2009 as the Company replaces expiring coal contracts at these dramatically higher market prices. However, witness Batson stated that the expected average cost for the billing period September 2008 through August 2009 is still significantly lower than the current and projected market price for Central Appalachia coal. Witness Batson testified that the Company is not aware of any significant changes in transportation costs forthcoming in 2008 and 2009 as compared to 2007, with the exception of: (1) fuel surcharges tied to the price per barrel of oil and (2) rail contract rate increases for inflationary factors pursuant to the terms and conditions of the relevant contracts.

Company witness Geer testified regarding Duke Energy Carolinas' nuclear fuel costs during the test year and changes expected in 2008 and 2009. Witness Geer stated that the most pronounced change occurred in the uranium concentrates sector, where spot market prices have increased nearly tenfold since market lows occurred in calendar year 2000 and where such prices remain well above historical norms; however, the impact of these higher market prices on the Company during the test period was mitigated by contracts negotiated at lower market prices prior to the test period. Witness Geer noted that industry consultants expect spot market prices to remain high in comparison to historic norms as exploration, mine construction, and production gear up. Witness Geer further testified that market prices for enrichment have increased approximately eighty percent since market lows experienced in calendar year 2000. He stated that one hundred percent of the Company's enrichment purchases during the test period were delivered under long term contracts negotiated at lower market prices prior to the test period. As such, the test period enrichment costs are comparable to the previous test period and notably less than spot market prices in the same period. Witness Geer testified that as these contracts expire, they will be replaced with contracts at higher market prices.

Witness Geer testified that Duke Energy Carolinas does not anticipate a significant increase in nuclear fuel expense through the next billing cycle period. Because fuel is typically expensed over two to three operating cycles - roughly three to five years - Duke Energy Carolinas' nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period as well as during prior periods. He stated that the costs of the fuel residing in the reactors during the test period will be predominantly based on contracts negotiated prior to the recent market price increases. As fuel with a low cost basis is discharged from the reactor and lower priced legacy contracts expire, nuclear fuel expense is expected to increase in the future.

Witnesses Batson and Roebel testified concerning Duke Energy Carolinas' Reagent costs and net gains from By-Product sales during the test year and about changes expected in 2008 and 2009. These witnesses testified that, as additional environmental control equipment is placed in service, Reagent costs are expected to increase. Expenses for limestone, ammonia, urea and dibasic acid used in the operation of flue-gas desulfurization, selective catalytic reduction and selective non-catalytic reduction equipment are projected to be approximately $33.4 million for the September 2008 through August 2009 period.

Witness Roebel testified that the Company seeks to sell By-Products from the combustion or environmental treatment processes where there is a market for such materials as a means to minimize or offset the costs it would otherwise incur for their disposal. Coal ash sales resulted in net gains during the test period. Gypsum management activities required a net cost to complete; however, these net costs are significantly lower than the disposal costs the Company would otherwise incur. Net gains from By-Product management activities are expected to reach $2.2 million for the upcoming billing period.

Evidence concerning the reasonable and efficient operation of Duke Energy Carolinas' fossil-fueled, hydroelectric and nuclear generating facilities is discussed above in the Evidence and Conclusions for Finding of Fact Nos. 4-6.

Witness McManeus recommended fuel and fuel-related prices and expenses as follows:

A. The coal fuel price is $31.96/MWh.
B. The oil and gas fuel price is $97.82/MWh.
C. The appropriate Light Off fuel expense is $12,640,000.
D. The appropriate ammonia, limestone, urea and dibasic acid (collectively "Reagents") expense is $33,397,000.
E. The appropriate net proceeds on sale of By-Products are ($2,218,000).
F. The total nuclear fuel price is $4.83/MWh.
G. The nuclear fuel price for Catawba generation is $4.71/MWh.
H. The non-capacity purchased power and other purchased power fuel price is $55.67/MWh.
I. The adjusted level of fuel and fuel-related credits associated with intersystem sales is $159,369,000.

Items A, B, C, D, E, F, H and I are set forth on or derived from McManeus Exhibit 1, Schedule 2(c). Item G is set forth on McManeus Appendix 1, Page 9 [ND-2302(c)].

Public Staff witness Lam testified that he recommended that the Commission approve Duke Energy Carolinas' proposed fuel factor. His recommendation was based upon a review of the Company's Application and coal contracts, an examination of the current coal market, and a review of the Company's fuel-related costs. By making this recommendation, Public Staff witness Lam implicitly agreed with the Company's proposed fuel prices and expenses. No party contested the Company's recommended fuel and fuel-related expenses.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the affidavit of Public Staff witness Johnson and the testimony and exhibits of Company witness McManeus.

Company witness McManeus explained that Senate Bill 3 added the "total delivered non-capacity related costs, including all related transmission charges, of all purchases of electric power by the electric public utility, that are subject to economic dispatch or economic curtailment" to the definition of "fuel-related costs", but that this amendment was not effective until January 1, 2008. Therefore, in calculating fuel expense for the 2007 test period Duke Energy Carolinas used the fuel-to-energy proxy to determine the fuel cost component of purchased power from certain suppliers. However, Duke Energy Carolinas has included a representative level of Non-Capacity Purchased Power costs in calculating the proposed fuel and fuel-related cost factor for the period September 1, 2008 through August 31, 2009.

In her affidavit, Public Staff witness Johnson presented her calculation of the appropriate fuel-to-energy percentage to be applied to the fuel costs associated with purchases from power marketers and other suppliers who provided power to the Company during the test year. Witness Johnson indicated that, in order to determine this percentage, the Public Staff performed an analysis of the fuel component of off-system sales made by Duke Energy Carolinas and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC"), which are set forth in the utilities' Monthly Fuel Reports, for the twelve months ended December 31, 2007. She stated that, as was the case with the most recent review for the twelve months ended December 31, 2006, the 2007 off-system sales for Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") were not utilized for purposes of calculating the fuel-to-energy percentage. Witness Johnson stated that the rationale for excluding DNCP from this analysis is two-fold. First, of the four counterparties for whom DNCP recorded off-system sales in 2007, one reported no fuel costs in conjunction with the recording of total energy dollars, and two appeared to use a "proxy percentage" to determine the fuel component of total energy rather than actual fuel cost. Second, the remaining counterparty was PJM Interconnection, LLC ("PJM"), with whom DNCP participates in complex contractual arrangements associated with DNCP's membership in the PJM Regional Transmission Organization. The fuel costs recorded by DNCP in conjunction with recorded 2007 off-system sales to PJM had fuel costs equal to exactly 100% of total energy dollars. In view of this fact, and in light of the complex nature of the relationship between DNCP and PJM, witness Johnson stated that the accounting for these transactions does not appear to reflect what one would expect from a stand-alone arrangement for the off-system sale of energy. Therefore, she stated that none of these transactions appears to provide meaningful data and that the Public Staff considers it reasonable to exclude them from the determination of the fuel-to-energy percentage.

Witness Johnson testified that, despite the removal of DNCP, the Public Staff's analysis is similar to that performed by the Public Staff for the 1997 Stipulation addressing this issue (which was applicable to the 1997 and 1998 fuel proceedings) and the similar 1999 Stipulation (which was filed by PEC on June 4, 1999, in Docket No. E-2, Sub 748, and intended by the parties to be applicable to the 1999, 2000, and 2001 fuel cost proceedings). Similar analyses were performed for the 2002 through 2007 fuel proceedings. The methodology used for each of the above-mentioned Stipulations and subsequent fuel proceedings has been accepted by this Commission as reasonable in each fuel case since the beginning of 1997.

Witness Johnson stated that, for purposes of determining fuel costs incurred through December 31, 2007, G.S. 62-133.2 requires that purchased power-related costs recovered through fuel proceedings consist of only the fuel cost component of those purchases. However, in its Order in Duke Energy Carolinas' 1996 fuel proceeding, the Commission stated that whether a proxy for actual fuel costs associated with these types of purchases would be acceptable in a future fuel proceeding would depend on "whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available." *Order Approving Fuel Charge Adjustment,* Docket No. E-7, Sub 575 (1996).

Witness Johnson testified in her affidavit that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for determining the proxy fuel cost as described above. Because the sales made by marketers and other suppliers utilize the same types of generation resources that the utilities use to make their sales, the Public Staff believes that it is reasonable to assume for purposes of these proceedings that the fuel-to-energy cost percentage inherent in the purchases made by the utilities is similar to the percentage exhibited by the utilities' sales. Additionally, the information used by the Public Staff to determine the off-system sales fuel percentage was derived from the Monthly Fuel Reports filed with the Commission and, in the opinion of the Public Staff, is reasonably reliable. Finally, the Public Staff is unaware of any alternative information currently available concerning the fuel cost component of marketers' sales made to utilities. Therefore, the Public Staff believes that the methodology used in the past Stipulations and in its analysis for this proceeding meets the criteria set forth in the 1996 Duke Energy Carolinas Order.

As part of its current review, witness Johnson stated that the Public Staff analyzed the off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 58.40% to 67.68%, as set forth on Johnson Exhibit 1. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel percentage should be 61%.

The Commission concludes, as it has in past proceedings, that the methodology underlying the 1997 and 1999 Stipulations, the use of the utilities' own off-system sales to determine the proxy fuel cost for purchases from entities that do not provide actual fuel cost information to the purchasing utility, is reasonable and satisfies the requirements set forth in the 1996 Duke Energy Carolinas fuel case order for purposes of calculating fuel costs incurred through December 31, 2007 in this proceeding. First, the results of applying the methodology can be accepted under G.S. 62-133.2 as it is applicable to purchased power costs incurred prior to January 1, 2008. As Public Staff witness Johnson stated in her affidavit, the sales made by marketers and other relevant suppliers are sourced from the same types of generation resources that the utilities regulated by this Commission use to make their sales. The Commission thus finds it reasonable to assume for purposes of this proceeding that the fuel-to-energy cost percentage exhibited by the utilities' sales is similar to the percentage inherent in the sales made to Duke Energy Carolinas from the same types of generating resources. Second, the Commission concludes that the information used by parties to derive the fuel percentage is reasonably reliable. According to Public Staff witness Johnson's affidavit, this data was derived from the Monthly Fuel Reports filed by the utilities with the Commission, which are public reports taken from the utilities' financial records and are subject to Commission review. Finally, no party to this proceeding has elicited evidence of any alternative information available concerning the fuel cost component of purchases made from power marketers or other similar sellers of power to Duke Energy Carolinas. Therefore, the Commission concludes that the methodology underlying the 1997 and 1999 Stipulations used in prior cases meets the criteria set forth in the 1996 Duke Energy Carolinas fuel case Order, and is reasonable for use in this proceeding as the method of determining the proxy fuel cost for purchased power costs incurred during the 2007 test period.

Given the fact that the Commission has concluded that the methodology underlying the 1997 and 1999 Stipulations is reasonable for purposes of this proceeding, the question remains as to the appropriate fuel percentage to be used in this case. As part of its current review, the Public Staff analyzed the off-system sales information in different ways. The Public Staff's analyses resulted in percentages ranging from 58.40% to 67.68%. Based on its analyses, the Public Staff concluded that 61% is an appropriate and reasonable fuel proxy percentage for purposes of this proceeding. Duke Energy Carolinas accepted the results of the analysis performed by the Public Staff and filed supplemental testimony and revised exhibits to reflect the 61% fuel percentage.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use a 61% fuel percentage as the basis for determining the proxy fuel costs for purchases during the test period from power marketers and other suppliers that did not provide actual fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-15

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness McManeus and the affidavits of Public Staff witnesses Johnson and Lam.

Based upon the agreement between the Company and the Public Staff as to the appropriate levels of sales, generation, and unit fuel costs, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 4-9, the Commission concludes that adjusted test period system fuel and fuel-related costs of $1,720,316,000 and a composite fuel and fuel-related costs factor of 2.1189¢/kWh, excluding gross receipts tax and regulatory fee (as set forth on McManeus Exhibit 1, Schedule 2(c)), are reasonable and appropriate for use in this proceeding. This fuel and fuel-related costs factor is 0.3819¢/kWh higher than the adjusted base fuel factor of 1.7370¢/kWh as set forth on McManeus Exhibit 1, Line 7.

Senate Bill 3 added G.S. 62-133.2(a2), which requires the utilities to develop separate components for the recovery of items (4) Non-Capacity Purchase Power costs, (5) QF Capacity costs and (6) Renewable Energy costs to be allocated to customer classes in accordance with the following:

(1) For the costs described in subdivision (4) of subsection (a1) of this section, the specific component for each class of customers shall be determined by allocating these costs among customer classes based on the electric public utility's North Carolina energy usage for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after 1 January 2008.

(2) For the costs described in subdivisions (5) and (6) of subsection (a1) of this section, the specific component for each class of customers shall be

> determined by allocating these costs among customer classes based on the electric public utility's North Carolina peak demand for the prior year, as determined by the Commission, until the Commission determines how these costs shall be allocated in a general rate case for the electric public utility commenced on or after 1 January 2008.

Witness McManeus testified that, in accordance with this set of statutory provisions, the Company calculated a Non-Capacity Purchased Power component for each of the Residential, General Service/Lighting and Industrial customer classes based upon the 2007 actual MWh sales for each of these classes. The resulting fuel and fuel-related cost factors are 2.1185¢/kWh for the Residential class, 2.1182¢/kWh for the General Service/Lighting class, and 2.1205¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee. Because Duke Energy Carolinas did not propose to include QF Capacity costs or Renewable Energy costs, it did not compute separate rider components based upon North Carolina peak demand. Witness McManeus explained that all other fuel and fuel-related costs are charged to all customer classes based on adjusted test period MWh sales. Additionally, consistent with G.S. 62-133.2(a3), witness McManeus demonstrated that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs and renewable energy costs did not exceed two percent of Duke Energy Carolinas' total North Carolina jurisdictional gross revenues for 2007.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

Public Staff witness Johnson testified about the results of the Public Staff's investigation of the Experience Modification Factor ("EMF"). The EMF rider is utilized to "true-up" the recovery of fuel costs incurred during the test year pursuant to G.S. 62-133.2(d) and Commission Rule R8-55. The Public Staff's investigation included procedures to evaluate whether the Company properly determined its per books fuel and fuel-related costs and revenues during the test period. These procedures included review of the Company's filing, prior Commission Orders, the Monthly Fuel Reports filed by the Company with the Commission, and other Company data provided to the Public Staff. Additionally, the procedures performed by the Public Staff included review of certain specific types of expenditures impacting the Company's test year fuel cost, including nuclear fuel disposal costs, federally mandated payments for decommissioning and decontamination of Department of Energy uranium enrichment facilities, payments to non-utility generators, and purchases of power from other suppliers who may or may not have provided the actual fuel costs associated with those purchases. Also, the Public Staff's procedures included reviews of source documentation of fuel costs for certain selected Company generation resources. Performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as a site visit to the Company's offices.

As discussed above in the Evidence and Conclusions for Finding of Fact No. 10, Public Staff witness Johnson recommended that a factor of 61% be used to determine the fuel costs associated with power purchased from power marketers and other suppliers that did not provide the Company with the actual fuel costs associated with those purchases. In her supplemental testimony, Duke Energy Carolinas witness McManeus presented Revised McManeus Exhibit 6 setting forth the Company's revised recommended EMF increment. Witness McManeus testified that she applied the 61% fuel percentage proxy to the costs of purchased power incurred during the test period from suppliers that did not provide actual fuel costs and to intersystem sales of power for which actual fuel cost was unknown. The total under-recovery set forth on Revised McManeus Exhibit 6, page 1 of 2 is $32,033,000. Witness Johnson stated in her affidavit that the Public Staff does not disagree with the Company's adjustment, and that her investigation did not reveal any other necessary adjustments to Duke Energy Carolinas' initially reported test year North Carolina retail fuel cost under-recovery or its proposed EMF. Witness Johnson testified that the Public Staff recommended that Duke Energy Carolinas' EMF increment rider be based upon a net fuel cost under-recovery of $32,033,000 and pro forma North Carolina retail sales of 55,014,640 MWh, as reflected in Revised McManeus Exhibit 6. Based upon the evidence in the record and the agreement of the Company and the Public Staff, the Commission concludes that Duke Energy Carolinas' reasonable North Carolina retail jurisdictional fuel expense under-collection is $32,033,000, and that 55,014,640 MWh is the reasonable level of test year adjusted North Carolina retail sales to be used to calculate the EMF increment rider.

Company witness McManeus calculated the EMF increment by dividing the $32,033,000 under-recovered fuel expense by the adjusted North Carolina jurisdictional sales of 55,014,640 MWh to arrive at an EMF increment of 0.0582¢/kWh, excluding gross receipts tax and regulatory fee. Public Staff witness Johnson recommended the same EMF increment. The Commission concludes that an EMF increment of 0.0582¢/kWh, excluding gross receipts tax and regulatory fee, is reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.1767¢/kWh for the Residential class, 2.1764¢/kWh for the General Service/Lighting class, and 2.1787¢/kWh for the Industrial class, excluding gross receipts tax and regulatory fee, consisting of prospective fuel factors of 2.1185¢/kWh, 2.1182¢/kWh, and 2.1205¢/kWh, respectively, for the relevant customer classes and an EMF increment of 0.0582¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 16-18

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness McManeus.

As discussed above in the Evidence and Conclusions for Findings of Fact Nos. 4-6, consistent with the Rate Order in the Company's last general rate case, as of January 1, 2008, all of Duke Energy Carolinas' Nantahala Area customers will pay fuel costs based on Duke Energy Carolinas' existing fuel adjustment charge. Witness McManeus testified that this transition results in the termination of the Interconnection Agreement between Duke Power Company (now known as Duke Energy Carolinas, LLC) and Nantahala Power and Light Company

("Nantahala") dated October 7, 1987 ("Interconnection Agreement"). The Agreement and Stipulation of Partial Settlement ("Stipulation") approved in the Rate Order provides that "[t]he balance at December 31, 2007 of the Nantahala energy bank less the unamortized balance of purchased power cost will be evaluated in a future fuel adjustment rider proceeding."

Witness McManeus explained that the Interconnection Agreement contains a contractual feature called the Energy Bank in recognition of the fact that the generation from Nantahala's owned resources, which were all hydroelectric, varied directly with the amount of rainfall experienced. The Energy Bank was established as a mechanism to smooth the effects of weather on retail customer bills as Nantahala supplemented its generation requirements by purchasing power from the Company at a higher cost. This mechanism has remained in place for the benefit of Nantahala customers. *Order Approving Combination of Nantahala Power and Light Company and Duke Energy Corporation and Transfer of Nantahala Franchise* Docket Nos. E-7, Sub 614 and E-13, Sub 178 (April 8, 1998).

Witness McManeus testified that the balance in the Energy Bank as of December 31, 2007 was a payable to Duke Energy Carolinas from Duke Energy Nantahala Area customers of $11,825,036. This amount is the additional purchased power expense to the Nantahala Area customers resulting from the fact that that Nantahala's actual hydroelectric generation was well below the average hydroelectric generation used in determining the over or under recovery for purposes of calculating Rider CP. Upon termination, the Interconnection Agreement provides for the entire balance of the Energy Bank to be included as a charge or credit to purchased power expense for Nantahala Area customers.

Witness McManeus testified that Duke Energy Carolinas proposed to reduce the Energy Bank balance by: (1) applying the over-recovery balance at December 31, 2007 resulting from the currently approved Rider CP and the over-recovery balance of purchased power costs experienced from August 2007 through December 31, 2007 to reduce the Energy Bank balance at December 31, 2007; (2) reducing the net deferred cost balance by the balance of unclaimed refunds applicable to the Nantahala Area customers under the Commission's Order dated November 30, 1989 in Docket No. E-13, Subs 29, 35 and 44, which allowed Nantahala to treat unclaimed rate refunds as cost free capital to Nantahala; and (3) identifying the North Carolina retail EMF component of the fuel and fuel-related costs adjustment charge through the last month the EMF that is determined in this proceeding is billed to the Nantahala Area customers and applying the amount identified to reduce the net deferred cost balance in light of the fact that, through Rider CP and the provisions of the Energy Bank, Duke Energy Carolinas will have already charged its Nantahala Area Customers for actual fuel costs incurred in providing service through December 31, 2007. The net Energy Bank balance at December 31, 2007 reduced by the amounts identified in (1) and (2) above as proposed is $7,414,854. The Company estimates that item (3) above as proposed will result in an additional $1.4 million collected from Nantahala Area customers through June 30, 2008 to further reduce the Energy Bank balance.

Witness McManeus testified that Duke Energy Carolinas proposes to recover the net deferred cost balance of the Energy Bank by implementing a Nantahala Rider applicable to Nantahala Area customers designed to collect additional revenue equal to 2% of the revenues the Company received from its Nantahala Area customers for the calendar year ending

December 31, 2007. She stated that the Nantahala Rider would continue to be billed to the Nantahala Area customers until the Company is reimbursed for the net deferred cost balance. The Company does not propose to charge its Nantahala Area customers interest on the outstanding deferred balance subsequent to December 31, 2007. The Commission agrees that the Nantahala Rider as proposed by the Company is needed to recover the deferred purchased power costs owed from Nantahala Area customers under the terms of the Interconnection Agreement consistent with the Rate Order. Accordingly, the proper Nantahala Area Customer Rider for the 2008-2009 billing period is 0.1539¢/kWh, excluding gross receipts tax and regulatory fee.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after September 1, 2008, Duke Energy Carolinas shall adjust the base fuel and fuel-related costs in its North Carolina retail rates approved in Docket No. E-7, Sub 828 as adjusted in this proceeding to 1.7370¢/kWh by an amount equal to an increase of .3815¢/kWh increase for the Residential class, .3812¢/kWh for the General Service/Lighting class, and .3835¢/kWh for the Industrial class (excluding gross receipts tax and regulatory fee), and, further, that Duke Energy Carolinas shall adjust the resultant approved fuel and fuel-related costs by an increment of 0.0582¢/kWh (excluding gross receipts tax and regulatory fee) for the EMF increment. The EMF increment is to remain in effect for service rendered through August 31, 2009;

2. That, effective for service rendered on and after September 1, 2008, Duke Energy Carolinas shall increase rates for customers in the Nantahala Area by 0.1539¢/kWh (excluding gross receipts tax and regulatory fee) for recovery of the net deferred purchased power costs represented by the Energy Bank balance. This Nantahala Area Customer Rider shall remain in effect for service rendered through August 31, 2009;

3. That Duke Energy Carolinas shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order; and

4. That Duke Energy Carolinas shall notify its North Carolina retail customers of these rate adjustments by including the "Notice to Customers of Change in Rates" attached as Appendix A as a bill insert with bills rendered during the Company's next normal billing cycle.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of August, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr080808.02

APPENDIX A
Page 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 847

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC	)	
Pursuant to G.S. 62-133.2 and NCUC	)	NOTICE TO CUSTOMERS
Rule R8-55 Relating to Fuel and Fuel	)	OF CHANGE IN RATES
Related Cost Adjustments for Electric	)	
Utilities – 2008	)	

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order in Docket No. E-7, Sub 847, on August 8, 2008, after public hearings, approving fuel and fuel-related charge rate increases of 0.3476, 0.3473 and 0.3497 cents per kWh (including North Carolina gross receipts tax and regulatory fee) for the Residential, General Service/Lighting and Industrial customer classes, respectively, or approximately $191,451,000 on an annual basis, in the rates and charges paid by the retail customers of Duke Energy Carolinas in North Carolina, effective for service rendered on and after September 1, 2008. The rate increase was authorized by the Commission after review of Duke Energy Carolinas' fuel and fuel-related expenses during the 12-month period ended December 31, 2007, and represents actual changes experienced by the Company with respect to its reasonable cost of fuel and fuel-related costs during the test period. Pursuant to G.S. 62.133.2(a2)(1), the net fuel and fuel-related cost factors for the Residential, General Service/Lighting and Industrial customer classes are 2.2519, 2.2516 and 2.2540 cents per KWH respectively.

The change in approved rates will result in a monthly net rate increase of approximately $3.48 for each 1,000 kWh of usage per month for the Residential customer class, $3.47 for each 1,000 kWh of usage per month for the General Service/Lighting customer class, and $3.50 for each 1,000 kWh of usage per month for the Industrial customer classes.

Additionally, the Commission approved a rate increase of .1592 cents per kWh (including North Carolina gross receipts tax and regulatory fee) in the rates and charges paid by the retail customers located in Duke Energy Carolinas Nantahala Area, effective for service rendered on and after September 1, 2008. The rate increase was ordered in connection with the transition of these customers to Duke Energy Carolinas' rates and is intended to recover, over a period of several years, the reasonable net deferred purchased power costs incurred by the Company in providing service to these customers prior to January 1, 2008.

The additional change in approved rates for Nantahala Area customers will result in an additional monthly net rate increase of approximately $1.59 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of August, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount. Deputy Clerk

mr080808.02

DOCKET NO. E-22, SUB 451

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Dominion North Carolina Power for	)	ORDER APPROVING
Authority to Adjust its Electric Rates Pursuant to	)	FUEL CHARGE
G.S. 62-133.2 and NCUC Rule R8-55	)	ADJUSTMENT

HEARD: Friday, November 14, 2008, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Robert V. Owens, Jr., and William T. Culpepper, III

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, 3700 Glenwood Avenue, Suite 330, Raleigh, North Carolina 27612

Joseph K. Reid, III, McGuire Woods, LLP, One James Center, 901 East Cary Street, Richmond, Virginia 23219

For the Carolina Industrial Group for Fair Utility Rates I:

Ralph McDonald, Bailey and Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

For Nucor Steel-Hertford:

Joseph W. Eason, Nelson, Mullins, Riley & Scarborough, LLP, 4140 ParkLake Avenue, Glen Lake One, Suite 200, Raleigh, North Carolina 27612

For the Using and Consuming Public:

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

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: G.S. 62-133.2 requires the Commission to hold a hearing for each electric utility engaged in the generation and production of electric power by fossil or nuclear fuel for the purpose of determining whether an increment or decrement rider is required to reflect actual changes in the cost of fuel and the fuel component of purchased power over or under the base fuel component established in the last general rate case. In addition, the Commission is required to incorporate in its fuel cost determination the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test year. The last general rate case Order for Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (NC Power or the Company), was issued by the Commission on March 18, 2005, in Docket No. E-22, Sub 412. The last Order approving a fuel charge adjustment for the Company was issued on December 20, 2007, in Docket No. E-22, Sub 444.

On August 29, 2008, NC Power filed a letter informing the Commission of its pending application. On September 2, 2008, the Carolina Industrial Group for Fair Utility Rates I (CIGFUR) filed a petition to intervene, which was granted by Order dated September 9, 2008. On September 3, 2008, Commission issued its Order Regarding Scheduling of Hearing. Also on that date, pursuant to G.S. 62-133.2 and Commission Rule R8-55, NC Power filed its Application and the direct testimony and exhibits of Kurt W. Swanson, Manager – Regulatory & Pricing; Glenn A. Kelly, Director of Generation System Planning; Gregory J. Morgan, Managing Director – Energy Supply; Alan L. Meekins, Director – Electric Market Operations; Gregory A. Workman, Director – Fuels; and Wesley S. Gregory, Director of Generation Accounting. The Company also filed the confidential testimony and exhibits of Alan L. Meekins and confidential Exhibit No. GJM-2 on September 3, 2008.

Nucor Steel-Hertford (Nucor), a division of Nucor Corporation, filed a petition to intervene on September 4, 2008, which was granted by Order dated September 12, 2008. Also on September 12, 2008, the Commission issued its Order Scheduling Hearing and Requiring Public Notice.

The Attorney General filed Notice of Intervention on September 29, 2008. On October 22, 2008, CIGFUR filed its Motion to Compel Discovery, which was denied by Order dated October 27, 2008. On October 28, 2008, Nucor filed a motion for amendments to the procedural schedule, requesting that the due date for intervenor testimony be extended from October 30, 2008, to November 3, 2008, and the due date for NC Power's rebuttal testimony be extended from November 7, 2008, to November 10, 2008. By Order dated October 30, 2008, the Commission granted the requested extensions of time. On October 29, 2007, the Company filed its Affidavits of Publication.

On November 3, 2008, Nucor filed the testimony and exhibits of Paul J. Weilgus and the confidential and redacted testimony and exhibits of Dr. Mathew J. Morey. Also on November 3, 2008, the Public Staff filed the affidavit and exhibits of Darlene P. Peedin, Staff

Accountant, and the affidavit of Thomas S. Lam, Electric Engineer, and CIGFUR filed the testimony and exhibits of Nicholas Phillips, Jr.

On November 10, 2008, NC Power filed the rebuttal testimony of Kurt W. Swanson, Gregory J. Morgan, and Wesley S. Gregory and the confidential rebuttal testimony and revised exhibits of Alan L. Meekins and confidential revised attachments to Gregory J. Morgan's Exhibit No. GJM-2. A Settlement Agreement between NC Power and the Public Staff was filed on November 13, 2008.

Several consumer statements of position and resolutions opposing NC Power's requested rate increase were filed and made part of the record, including resolutions adopted by the Dare County Board of Commissioners, the Town of Columbia Board of Aldermen, the Tyrrell County Board of Commissioners, the Southern Shores Town Council, and the Board of Commissioners of the Town of Nags Head, North Carolina.

At the hearing held on November 14, 2008, the prefiled direct testimony and rebuttal testimony of the Company's witnesses, the affidavits and exhibits of the Public Staff's witnesses, and the testimony and exhibits of CIGFUR's and Nucor's witnesses were admitted into evidence. No public witnesses appeared at the hearing. NC Power notified the Commission that NC Power had reached agreement on certain terms with the other parties, which as to CIGFUR and Nucor would be reduced to writing and filed as soon as possible. CIGFUR and Nucor had questions of NC Power witness Swanson and Public Staff witness Lam, who were made available for those questions. The Attorney General notified the Commission that it was in accord with the settlement between NC Power and the Public Staff. CIGFUR and Nucor notified the Commission that they were in accord with the settlement between NC Power and the Public Staff, except for the allocation of the increase among customer classes.

On December 4, 2008, the Company filed an agreement between NC Power and Nucor and an agreement between NC Power and CIGFUR.

Based upon the verified Application, the evidence adduced at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. NC Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. NC Power is lawfully before the Commission based on its Application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2008.

3. The Company's fuel procurement and purchasing practices during the test period were reasonable and prudent.

4. The test period per book system sales are 83,474,539 MWh.

5. The test period per book system generation is 85,366,798 MWh, which includes various types of generation as follows:

Generation Type	MWh
Coal	31,633,749
Combined Cycle and Combustion Turbine	5,217,141
Heavy Oil	609,085
Nuclear	25,717,619
Hydro	2,165,585
Pumped Storage (Pumping)	(2,333,012)
Power Transactions	
NUG	10,167,613
Other	13,368,943
Sales for Resale	(1,179,926)

6. The nuclear capacity factor appropriate for use in this proceeding is 92.2%, which is the estimated nuclear capacity factor for the 12 months beginning January 1, 2009.

7. The adjusted test period system sales for use in this proceeding are 83,563,301 MWh.

8. The adjusted test period system generation for use in this proceeding is 85,465,935 MWh, which is categorized as follows:

Generation Type	MWh
Coal	31,518,984
Combined Cycle and Combustion Turbine	5,198,223
Heavy Oil	606,901
Nuclear	26,038,041
Hydro	2,165,585
Pumped Storage (Pumping)	(2,333,012)
Power Transactions	
NUG	10,130,737
Other	13,320,402
Sales for Resale	(1,179,926)

9. Setting the fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 70% of the energy portion of the purchase price is reasonable for purposes of this proceeding.

10. The appropriate fuel prices for use in this proceeding are as follows:

A. \$25.72/MWh for coal;
B. \$4.51/MWh for Surry and \$4.59/MWh for North Anna – nuclear;
C. \$105.49/MWh for heavy oil;
D. \$81.61/MWh for combined cycle and combustion turbine fuel;
E. \$7.56/MWh for NUG Power Transactions Fuel; \$56.86/MWh for Purchases (@ 70%) and \$44.97/MWh for Sales for Resale; and,
F. A zero fuel price for hydro and pumped storage.

11. The adjusted test period system fuel expense for use in this proceeding is \$2,198,335,166.

12. The proper fuel factor for this proceeding is 2.631¢/kWh, excluding gross receipts tax, or 2.718¢/kWh, including gross receipts tax.

13. The approach contained in the NC Power/Nucor Settlement Agreement filed on December 4, 2008, as to the study NC Power is required to conduct for its next fuel clause proceeding to demonstrate that it has complied with Ordering Paragraph 1(e) of the Order Approving Transfer with Conditions issued April 19, 2005, in Docket No. E-22, Sub 418, is reasonable.

14. The appropriate North Carolina test period jurisdictional fuel expense undercollection is \$20,335,525. The adjusted North Carolina jurisdictional test year sales are 4,304,276 MWh.

15. The appropriate Experience Modification Factor (EMF) for this proceeding is an increment of 0.472¢/kWh, excluding gross receipts tax, or 0.488¢/kWh including gross receipts tax.

16. The final net fuel factor to be billed to NC Power's North Carolina retail customers during the 2008 fuel clause billing period is 3.103¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 2.631¢/kWh and the EMF increment of 0.472¢/kWh; or 3.206¢/kWh, including gross receipts tax, consisting of the prospective fuel factor of 2.718¢/kWh and the EMF increment of 0.488¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for NC Power. The Company's filing was based on the 12 months ended June 30, 2008.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on July 10, 2008. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

No party offered testimony contesting the Company's fuel procurement and power purchasing practices. Based on the fuel procurement practices report, the Commission concludes that these practices were reasonable and prudent during the test period.

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

The evidence for these findings of fact is contained in the testimony of Company witnesses Swanson and Kelly and the affidavit of Public Staff witness Lam.

Company witness Swanson testified that the Company's the test period per book system sales were 83,474,539 MWh, and witness Kelly testified that the Company's test period per book system generation was 85,366,798 MWh. The test period per book system generation is categorized as follows:

Generation Type	MWh
Coal	31,633,749
Combined Cycle and Combustion Turbine	5,217,141
Heavy Oil	609,085
Nuclear	25,717,619
Hydro	2,165,585
Pumped Storage (Pumping)	(2,333,012)
Power Transactions	
NUG	10,167,613
Other	13,368,943
Sales for Resale	(1,179,926)

Commission Rule R8-55(c)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Reliability Council's (NERC) Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events.

Company witness Kelly testified that, for the July 1, 2007, to June 30, 2008, test period, North Anna Unit 1 performed at a net capacity factor of 90.20%, North Anna Unit 2 performed at a net capacity factor of 93.93%, Surry Unit 1 performed at a factor of 87.68%, and Surry Unit 2 performed at a factor of 94.23%. He testified that all four of the Company's nuclear units exceeded the NERC 2002-2006 five-year industry average net capacity factor of 85.08% for units 400-799 MW and 88.80% for units 800-999 MW. He further testified that, for the 12 months ending December 31, 2009, North Anna Unit 1 is projected to operate at a net capacity factor of 91.0%, North Anna Unit 2 is projected to operate at a net capacity factor of 98.7%, Surry Unit 1 is projected to operate at a net capacity factor of 91.28%, and Surry Unit 2 is projected to operate at a net capacity factor of 91.21%.

Public Staff witness Lam testified that the Company's proposed fuel factor is based on a 92.2% system nuclear capacity factor, which is what the Company anticipates for the 12 months beginning January 1, 2009, the period the new rates will be in effect. The actual system nuclear capacity factor for the test year was 91.5%. In comparison, the latest NERC five-year (2002-2006) weighted average nuclear capacity factor for Pressurized Water reactors was 87.48%. He testified that he believed the proposed 92.2% nuclear capacity factor to be more representative of the factor the Company can reasonably be expected to achieve during the period that the fuel factor is in effect than the NERC five-year average. No other party offered or elicited testimony on the normalized nuclear capacity factor.

The Commission concludes that the July 1, 2007, to June 30, 2008, test period levels of sales and generation are reasonable and appropriate for use in this proceeding, as is the 92.2% normalized system nuclear capacity factor.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

Witness Swanson testified that the Company's system sales for the twelve months ended June 30, 2008, were adjusted for weather normalization, customer growth and increased usage in accordance with Commission Rule R8-55(d)(2). Witness Swanson adjusted total Company sales by 88,762 MWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 195,498 MWh, 89,451 MWh and (87,950) MWh, respectively, and an adjustment of (108,237) MWh from the restatement of non-jurisdictional ODEC sales from production level to sales level. The Public Staff reviewed and accepted these adjustments.

Based on the foregoing evidence, the Commission concludes that these adjustments are reasonable and appropriate adjustments for use in this proceeding. Therefore, the Company's adjusted system sales for the twelve months ended June 30, 2008, were 83,563,301 MWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the testimony of Company witness Kelly and the affidavit of Public Staff witness Lam.

Company witness Kelly presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2008, due to weather normalization, customer growth, and increased usage, to arrive at his adjusted generation level of 85,465,935 MWh. Public Staff witness Lam accepted witness Kelly's adjusted generation level, which includes various types of generation as follows:

Generation Type	MWh
Coal	31,518,984
Combined Cycle and	
Combustion Turbine	5,198,223
Heavy Oil	606,901
Nuclear	26,038,041
Hydro	2,165,585
Pumped Storage (Pumping)	(2,333,012)
Power Transactions	
NUG	10,130,737
Other	13,320,402
Sales for Resale	(1,179,926)

The Commission concludes that it is reasonable and appropriate to use 85,465,935 MWh in this proceeding as the amount of adjusted test period system generation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is contained in the testimony of NC Power witnesses Swanson and Morgan and the affidavit of Public Staff witness Peedin.

Witness Peedin stated that during the test year for this proceeding, NC Power purchased power from suppliers, primarily through the markets administered by PJM Interconnection, LLC (PJM), that did not provide NC Power with the actual fuel costs associated with those purchases.

In her affidavit, witness Peedin testified that the use of a fuel cost proxy for power marketers was first raised in Docket No. E-7, Sub 575. In its Order in that docket dated June 21, 1996, the Commission stated that whether a proxy for actual fuel costs associated with power purchases would be acceptable in a future fuel proceeding would depend on "whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available."

Witness Peedin indicated that in 1997, the Public Staff, Duke Power Company (now Duke Energy Carolinas, LLC (Duke)), Carolina Power & Light Company (now d/b/a Progress Energy Carolinas, Inc. (PEC)), and NC Power (collectively "the utilities"), agreed on a methodology to determine an appropriate fuel-to-energy percentage, which was filed in a 1997 Stipulation (which was applicable to the utilities' 1997 and 1998 fuel proceedings). A similar 1999 Stipulation was filed in Docket No. E-2, Sub 748 (applicable to the 1999, 2000, and 2001 fuel cost proceedings). Under this methodology, the Public Staff performed reviews of the aggregate fuel component of all off-system sales made by NC Power, Duke, and PEC, which are set forth in each of the utilities' Monthly Fuel Reports. Witness Peedin further testified that the fuel costs associated with the utilities' many sales to many counterparties was used to determine the fuel cost percentage to be applied to the utilities' many purchases from a large number of counterparties. As a result, an appropriate fuel-to-energy percentage was calculated using this methodology and used in each of the fuel proceedings held in 2002, 2003, 2004, and 2005. The methodology used for each of the above-mentioned Stipulations and fuel proceedings was accepted by the Commission as reasonable.

Witness Peedin testified that in 2005, NC Power integrated its system into PJM and, as a result, now makes virtually all of its purchases from the markets administered by PJM, which operates a specialized Locational Marginal Price (LMP) mechanism to determine the price NC Power pays for purchased power at any given time. She stated that as a result of integration with PJM, NC Power began making fewer off-system sales.

Company witness Morgan recommended a new methodology to determine the proxy fuel cost for its purchases from PJM in its fuel clause application. Witness Morgan testified that this methodology takes into account NC Power's unique situation of operating in a Regional Transmission Organization environment. Witness Morgan's proposed methodology calculates the fuel-to-energy percentages using three different methods, which are then averaged. Method 1 uses the relationship of the fuel costs of the marginal unit in the overall PJM dispatch stack in each hour to the LMPs for that hour, averaged over one year. Method 2 uses the fuel and non-fuel energy costs produced in the stand alone case from the PJM Fuel Study filed by NC Power in this fuel case and then adds an average percentage markup charged to purchases in the Dominion Zone of PJM. Method 3 utilizes the off-system sales of NC Power. Witness Morgan calculated the fuel percentages produced by these three methods for 2006 and for 2007 and then averaged the resulting six numbers together to produce his recommended fuel proxy percentage of 78%.

Public Staff witness Peedin testified that the Public Staff intends to continue to work with NC Power to adjust and refine Method 1 and/or Method 2 or to develop a related method organized along the same principles to more precisely estimate the fuel cost of purchased power. Witness Peedin testified that, for purposes of this proceeding, the Public Staff believes that NC Power has presented credible evidence that its purchased power fuel costs are greater than the 61% of total energy costs produced for 2007 by the traditionally utilized methodology. In addition, witness Peedin testified that, given NC Power's integration into PJM, NC Power has essentially been isolated from the markets to its south in which Duke and PEC buy and sell power, making the use of a percentage derived from Duke's and PEC's fuel costs less appropriate. She further testified that, based upon the Public Staff's investigation and pursuant to a settlement agreement between the Public Staff and NC Power, it was appropriate for the Commission to adopt, for purposes of this proceeding and the NC Power fuel proceeding to be filed in 2009, a percentage of 70% to be applied to purchases from the markets administered by PJM. Company witness Morgan testified that 70% was the average fuel-to-energy ratio in 2007 on a PJM poolwide basis as determined under Method 1 of the Company's fuel cost analysis. Company witness Swanson's rebuttal testimony indicated agreement with this description of the settlement, and the Attorney General, CIGFUR, and Nucor notified the Commission at the hearing that they were in accord with this part of the settlement as well.

Based upon the foregoing, the Commission concludes that it is reasonable to use a 70% fuel-to-energy percentage to be applied to NC Power's purchases from the markets administered by PJM as the proxy for actual fuel costs associated with such purchases for purposes of this proceeding.

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

The evidence for this finding of fact is contained in the testimony of Company witnesses Kelly and Swanson and the affidavit of Public Staff witness Lam.

In his affidavit, Public Staff witness Lam testified that, based upon settlement discussions with NC Power, he recommended that NC Power's fuel factor be calculated using the 12 months ended June 30, 2008, as shown on NC Power Exhibit GAK-1, Schedule 4, Column 4, for all Company-burned fuels (coal, nuclear, heavy oil and natural gas combined cycle and combustion turbine (CT) generating plants).

Company witness Swanson indicated in his rebuttal testimony that the Company originally proposed using end-of-period (June 2008) fuel costs for all fuel costs except purchased power, with the average cost of purchased power for the 12 months ended June 30, 2008, being used instead. Witness Swanson further testified that, pursuant to a settlement between NC Power and the Public Staff, the Company agreed to use the average costs for the 12 months ended June 30, 2008, for the remaining fuels (i.e., coal, nuclear, heavy oil, and natural gas for use in combined cycle and CT plants).

The Settlement Agreement between NC Power and the Public Staff (Settlement Agreement) containing the above-described agreement, among other things, was filed on November 13, 2008. The Attorney General notified the Commission at the hearing that it was in accord with this settlement. CIGFUR and Nucor notified the Commission at the hearing that they were in accord with this settlement, except for the allocation of the increase among customer classes.

The fuel prices agreed to in the Settlement Agreement for use in this proceeding, including the use of a 70% fuel-to-energy percentage as discussed above, are as follows:

A. $25.72/MWh for coal;
B. $4.51/MWh for Surry and $4.59/MWh for North Anna – nuclear;
C. $105.49/MWh for heavy oil;
D. $81.61/MWh for combined cycle and combustion turbine fuel;
E. $7.56/MWh for NUG Power Transactions Fuel; $56.86/MWh for Purchases (@ 70%) and $44.97/MWh for Sales for Resale; and,
F A zero fuel price for hydro and pumped storage.

Based upon the foregoing, the Commission concludes that these fuel prices are reasonable and appropriate for use in this proceeding.

Using the 70% fuel-to-energy percentage and the average fuel costs previously found to be appropriate for use in this proceeding, adjusted test period system fuel expenses are $2,198,335,166, which the Commission concludes is the appropriate level of fuel expenses to be used in this proceeding. The Commission further concludes that the resulting fuel cost rider

(Rider A) of 0.984¢/kWh, excluding gross receipts tax, or 1.017¢/kWh, including gross receipts tax, combined with the base fuel factor of 1.647¢/kWh, excluding gross receipts tax, or 1.701¢/kWh, including gross receipts tax, is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the testimony of Company witness Meekins and Nucor witness Morey.

At the outset, the Commission notes that the purpose of the PJM integration study (PJM Study) is to demonstrate that NC Power has complied with Ordering Paragraph 1(e) of the Order Approving Transfer with Conditions issued April 19, 2005, in Docket No. E-22, Sub 418 (PJM Order). In NC Power's last fuel cost adjustment proceeding (Docket No. E-22, Sub 444), the Commission concluded that NC Power should be required to perform and file a PJM Study run for the next fuel cost adjustment proceeding using a co-optimization approach, as generally advocated in Nucor's testimony in that proceeding, that seeks to find the least cost combination of purchases and dispatch of NC Power's generating units. The purpose of the requirement was to narrow the issues in controversy in order to facilitate the determination of a single methodology for the running of the PJM Study in future fuel proceedings for use in ascertaining whether NC Power's retail customers have been held harmless from the Company's integration into PJM.

Company witness Meekins testified that, based upon the direction provided by the Commission's Order dated April 4, 2008, in NC Power's last fuel case, the Company developed a model that co-optimizes the dispatch of Company generation with the purchase of off-system energy and submitted the resulting study to the Public Staff and other interested parties. The Company's study indicates that North Carolina ratepayers received fuel clause benefits in the range of $10 million and $15 million for the twelve-month study period through access to larger quantities of less expensive generation than would have been available had the Company remained an independent control area. Witness Meekins testified that these savings have been allocated to the Company's North Carolina retail customers and no adjustment is appropriate to comply with Ordering Paragraph 1(e) of the PJM Order.

In his pre-filed testimony, Nucor witness Morey testified that there were several problems with the Company's implementation of the co-optimization method approved by the Commission in the last fuel proceeding and with other assumptions made by the Company. He conducted an independent comparative fuel cost study to address these shortcomings, which produced lower estimates of the differences between a stand-alone case and a PJM case.

Although the Company did not necessarily agree with witness Morey's proposed changes to the study protocol, Nucor and the Company executed a Settlement Agreement on December 1, 2008, in which they agreed to meet, along with members of the Public Staff, to further discuss and undertake reasonable efforts to agree on the protocol for any fuel cost study conducted for next year's fuel clause proceeding. NC Power and Nucor agreed that such discussions would be limited to the propriety of including any or all of the four assumptions proffered by witness Morey in his pre-filed testimony in this proceeding (relating to transmission transfer limits, hourly purchases versus block purchase assumptions, transmission rates as hurdle rates, and restrictions on hour-to-hour purchase volatility). Furthermore, NC Power and Nucor agreed that any mutual agreements among these parties on changes to the existing protocol will govern the fuel cost study on a prospective basis, without further revision, unless otherwise ordered or agreed upon between the parties. No other party took issue with terms of this Settlement Agreement.

Based on the foregoing, the Commission concludes that the approach contained in the NC Power/Nucor Settlement Agreement as to the PJM Study to be conducted by NC Power in its next fuel clause proceeding is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 AND 15

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Gregory and Swanson and the affidavits of Public Staff witnesses Peedin and Lam.

Company witness Gregory testified that NC Power under-collected its fuel expenses by $24,553,955 during the test year ending June 30, 2008. Company witness Swanson testified that the adjusted North Carolina jurisdictional fuel clause test year sales were 4,304,276 MWh and that the appropriate EMF was 0.589¢/kWh.

Public Staff witness Peedin investigated the EMF to determine whether NC Power properly determined its fuel costs during the test period. Her investigation resulted in three adjustments. The first adjustment was to the purchased power costs related to using the 70% marketer percentage and resulted in a decrease to fuel expense in the amount of $4,397,379. The second adjustment was related to applying the 70% marketer percentage to credit the appropriate FTR revenue to purchased power costs. This adjustment increased fuel expense by $196,055. The third adjustment related to the correction of an error and resulted in a decrease to fuel expense in the amount of $17,106. The combination of the adjustments reduced NC Power's under-collected fuel expenses by $4,218,430. As a result, the Public Staff is proposing a test year under-recovery amount of $20,335,525 and an EMF increment of 0.472¢/kWh, excluding GRT, and 0.488¢/kWh, including GRT. In his rebuttal testimony, Company witness Gregory indicated the Company's concurrence with these three adjustments and the resulting proposed under-collected fuel deferral balance.

G.S. 62-133.2(d) provided in part that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period...in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

Company witness Swanson indicated that the appropriate and reasonable level of adjusted North Carolina retail sales for the test year is 4,304,276 MWh. No party disagreed with this level, and the Commission finds it reasonable. The $20,335,535 under-recovered fuel expense can thus be divided by the adjusted North Carolina jurisdictional sales of 4,304,276 MWh to arrive at an EMF increment of 0.472¢/kWh, excluding gross receipts tax, and 0.488¢/kWh, including gross receipts tax.

The Commission concludes that the EMF increments of 0.472¢/kWh; excluding gross receipts tax, and 0.488¢/kWh, including gross receipts tax, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is cumulative and is contained in the testimony and exhibits of Company witnesses Swanson and Gregory, the affidavits and exhibits of Public Staff witnesses Peedin and Lam, and the testimony and exhibits of CIGFUR witness Phillips.

Based upon the above findings and conclusions, the Commission finds and concludes that the final net fuel factor approved for use in this proceeding is 3.103¢/kWh, excluding gross receipts tax, and 3.206¢/kWh, including gross receipts tax.

This final net fuel factor is determined as follows:

Normalized System Fuel Expense	$2,198,335,166
System kWh Sales at Sales Level	83,563,300,726
Test Year North Carolina Retail Fuel Underrecovery	$20,335,525
North Carolina Retail kWh Sales at Sales Level	4,304,276,288
Base Fuel Component Approved in Docket No. E-22, Sub 412 (cents per kWh)	1.647
Gross Receipts Tax Factor	1.03327

Base Fuel Component including gross receipts tax = 1.701¢/kWh

Fuel Cost Rider A (excluding gross receipts tax)
= [($2,198,335,166)/83,563,300,726] - 1.647¢/kWh = 0.984¢/kWh

Fuel Cost Rider A (including gross receipts tax)
= 0.984¢/kWh x 1.03327 = 1.017¢/kWh

Fuel Cost Rider B (excluding gross receipts tax)
= [($20,335,525)/4,304,276,288 = 0.472¢/kWh

Fuel Cost Rider B (including gross receipts tax)
= 0.472¢/kWh x 1.03327 = 0.488¢/kWh

	Effective 1/1/2009 (Including Gross Receipts Tax)
Base Fuel Factor	1.701
EMF/Rider B	0.488
Fuel Cost Rider A	1.017
FINAL FUEL FACTOR	3.206

The Commission notes that the final net fuel factor of 3.206¢/kWh, including gross receipts tax, is a uniform rate to be applied to kWh sales to all customer classes. In NC Power's most recent fuel charge adjustment proceeding, Docket No. E-22, Sub 444, the Commission approved a final net fuel factor of 2.221¢/kWh, including gross receipts tax, and that uniform fuel factor will remain in effect until replaced by the uniform 3.206¢/kWh fuel factor approved herein. The 3.206¢/kWh uniform fuel factor will result in a .985¢/kWh increase over the 2.221¢/kWh uniform fuel factor currently in effect.

In his pre-filed direct testimony, CIGFUR witness Phillips testified that a uniform cents per kWh fuel factor over-allocated fuel costs to high load factors customers and resulted in a wide variation in the proposed revenue increase, on a percentage basis, for the different customer classes. Instead, witness Phillips recommended that the fuel cost increase should be distributed to customer classes on an equal percent revenue increase basis which would treat all customer classes in the same manner. This approach would result in a different ¢/kWh fuel factor for each customer class.

However, at the hearing, CIGFUR presented an alternative proposal for the allocation of the increased fuel costs in the form of CIGFUR Swanson Cross-Examination Exhibit No. 1. Page 1 of that exhibit shows, among other things, the different percent revenue increases for each customer class as a result of using the uniform .985¢/kWh increase. Page 2 of that exhibit sets forth the alternative proposal of CIGFUR that reduces the .985¢/kWh increment for the 6VP and NS customer classes to .885¢/kWh, but increases the .985¢/kWh increment for all other classes to 1.033¢/kWh.

In its brief, CIGFUR states that its alternative proposal would mitigate by one mill (or .1¢/kWh) the disproportionate impact of a uniform increase upon NC Power's largest, high load factor industrial customers without moving all the way to equal percent revenue increases for all customer classes as originally proposed by CIGFUR witness Phillips. CIGFUR notes that under its alternative proposal all other customer classes would receive a .048¢/kWh increase (or 48¢ per month for a typical residential customer) in addition to the .985¢/kWh increase resulting from the proposed 3.206¢/kWh uniform fuel factor. CIGFUR suggests that this relatively small shifting of cost responsibility would provide some much needed relief for NC Power's industrial base without unreasonably increasing the burden to other classes.

In support of its alternative proposal, CIGFUR first notes that Session Law 2007-397 (SB3) amended G.S. 62-133.2(a) to remove the word "uniform." Thus, this change in the statute authorizes the Commission to approve different riders for different customer classes provided that rates are just and reasonable and not unreasonably discriminatory. CIGFUR also states that uniform cents per kWh fuel factors have significant and disproportionate impacts on different classes of customers. Although the settlement agreement of NC Power and the Public Staff substantially lowers the increase proposed originally by the Company, the percentage revenue increases for 6VP and NS customers would still result in revenue increases of 17.35% for the 6VP class and 24.61% for Nucor (the customer on the NS class). In comparison, CIGFUR calculates that its alternative proposal would mitigate the impact of the uniform fuel charge such that the revenue increase would be reduced to 15.59% for the 6VP class and 22.11% for the NS class (or Nucor). CIGFUR also argues that the Commission may consider the "economic and political factors which are inherent in the ratemaking process." State ex rel. Utilities Commission v. Public Staff, 323 N.C. 481, 502 (1988). In this regard, CIGFUR states that its members and Nucor constitute a significant portion of NC Power's shrinking industrial base and that these entities are significant employers in the traditionally disadvantaged counties where they are located in terms of jobs, wages and income. In addition, CIGFUR points out that the Commission may also consider the type and manner of service to the customer in designing rates. State ex rel. Utilities Commission v. Public Staff, 323 N.C. at 502. CUCA notes that during cross-examination, it was established that 6VP and NS customers take electric service at either primary or transmission voltage levels. Line losses at the distribution level are approximately 6% whereas losses at the primary and transmission levels are approximately 4% and 2% respectively. As a result, 6VP and NS customers cause less electricity to be lost, with attendant fuel costs savings, than customers who take service at the distribution level. According to CIGFUR, this difference is not reflected in a uniform fuel charge. Finally, CIGFUR states that both the Company and the Public Staff would not oppose a policy decision by the Commission to adopt the alternative proposal of CIGFUR.

In its brief, Nucor argues that the Commission should approve the non-uniform rates set forth in CIGFUR Swanson Cross-Examination Exhibit No. 1 for essentially the same reasons set forth in the brief of CIGFUR as discussed above.

In adopting the 3.206¢/kWh fuel factor, the Commission has rejected the alternative proposal made by CIGFUR in this proceeding. The Commission notes that under the Settlement Agreement of the Company and the Public Staff, the 3.206¢/kWh uniform fuel factor produces an increase of $9.85 per 1,000 kWh for all customers, including residential customers. The alternative proposal of CIGFUR would add an additional 48¢ per 1,000 kWh to the bills of the customers in the residential, small general service, large general service, public authority, and OL/T classes. In the judgment of the Commission, all things considered, including the current economic situation, the Commission will impose no more than the $9.85 per 1,000 kWh increase on any customer class at this time. The Commission understands the importance of the customers in the 6VP and NS classes as employers in the NC Power service territory, but the alternative rate design proposed by CIGFUR and Nucor would shift 48¢ per 1,000 kWh to the customers in the LGS and SGS classes who are also employers. CIGFUR Swanson Cross-Examination Exhibit No. 1 shows that the LGS customer class has higher adjusted kWh sales than the 6VP class. On page 1 of this exhibit, which shows the NC Power proposed revenue increase, the LGS class would receive a 15.90% increase and 6VP customers would receive a 17.35% increase. On page 2 of this exhibit, showing the revenue increase under the alternative proposal, the LGS class would receive an increase of 16.68%, which is even higher than the 15.59% increase of the 6VP class. Both the LGS class and 6VP class are employers, but the alternative rate design proposal would shift costs from the 6VP class, such that the LGS class would receive an increase even greater than the 6VP class. Further, the alternative proposal would not remedy the wide variation of revenue increases to be experienced by the different customer classes, of which CIGFUR witness Phillips complained. Therefore, the Commission will not accept the alternative proposal of CIGFUR and Nucor, given the individual facts and circumstances surrounding this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2009, NC Power shall adjust the base fuel component in its North Carolina retail rates approved in Docket No. E-22, Sub 412, by an increment Rider A of 0.984¢/kWh, excluding gross receipts tax, or 1.017¢/kWh, including gross receipts tax;

2. That an EMF Rider increment (Rider B) of 0.472¢/kWh, excluding gross receipts tax, or 0.488¢/kWh, including gross receipts tax, shall be instituted and remain in effect for usage from January 1, 2009, until December 31, 2009;

3. That NC Power shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein not later than five (5) working days from the date of receipt of this Order;

4. That NC Power shall notify its North Carolina retail customers of the rate adjustments approved in this proceeding by including the Notice to Customers of Rate Increase attached to this Order as Appendix A as a bill insert with customer bills rendered during the next regularly scheduled billing cycle; and

5. That, with respect to the study required to determine compliance with Ordering Paragraph 1(e) of the PJM Order, NC Power shall meet with Nucor and the Public Staff and, and as discussed herein, undertake reasonable efforts to reach mutual agreements on changes to the existing protocol that will govern the PJM Study on a prospective basis, without further revision, unless otherwise ordered or agreed upon by the parties.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr121508.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 451

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Dominion North Carolina	)	
Power for Authority to Adjust its Electric	)	NOTICE TO CUSTOMERS
Rates Pursuant to G.S. 62-133.2 and	)	OF RATE INCREASE
NCUC Rule R8-55	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 19, 2008, after public hearing, approving an increase of $42,397,121 in the annual rates and charges paid by customers of Virginia Electric and Power Company, d/b/a in North Carolina as Dominion North Carolina Power. The rate increase will be effective for usage on and after January 1, 2009. The rate increase was approved by the Commission after review of Dominion North Carolina Power's fuel expenses during the 12-month test period ended June 30, 2008, and represents changes experienced by Dominion North Carolina Power with respect to its reasonable costs of fuel and the fuel component of purchased power.

The change in the approved fuel charge will result in a monthly net increase of approximately $9.85 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr121508.01

DOCKET NO. E-22, SUB 451

Chairman Edward S. Finley, Jr., concurring:

I find the arguments that CIGFUR and Nucor advanced in this docket persuasive and debate whether to concur or to dissent with the Commission's decision in this proceeding to adopt the uniform increment fuel rider in the settlement agreement between the Company and the Public Staff and to reject the two increment fuel riders in the alternative proposal set forth by CIGFUR and supported by Nucor.

The settlement agreement between the Company and the Public Staff results in a fuel cost increase of $9.85 per 1,000 kWh for all customers. The alternative proposal of CIGFUR would reallocate the fuel cost increase such that the increase for the 6VP and NS customer rate classes would be $8.85 per 1,000 kWh, and the increase for all the other customer rate classes would be $10.33 per 1,000 kWh. In other words, the alternative proposal of CIGFUR would reduce the increase for the 6VP and NS customer classes by $1.00 per 1,000 kWh and add 48¢ per 1,000 kWh to the increase for all other customer classes. Thus, the alternative proposal would add 48¢ to the bill of a typical residential customer using 1,000 kWh per month.

CIGFUR and Nucor raise several concerns, and what I consider to be strong points, in support of the alternative proposal. First, they cite that the General Assembly recently amended G.S. 62-133.2(a) to remove the word "uniform" and that this statutory change clearly permits the Commission to authorize the charging of different fuel riders. They also note that the uniform fuel rider results in a higher revenue or bill increase, on a percentage basis, for the 6VP and NS customer rate classes than the increase for all of the other rate classes. In addition, they point out that the uncontested testimony of Company witness Swanson indicates that 6VP and NS customers take service at either the transmission or primary level where line losses are at the 2% and 4% level, respectively. Conversely, residential customers take service at the distribution level where line losses are at the 6% level. Yet, uniform fuel factors do not recognize this difference in fuel cost causation. Therefore, CIGFUR and Nucor argue that the two increment fuel riders in the alternative proposal are legally permissible, more equitable, and supported by fuel cost causation.

CIGFUR and Nucor also point out that 6VP and NS customers are large employers in the NC Power service territory. They effectively argue that it would be better to lower the increase for 6VP and NS customers from 17.35% and 24.61%, to 15.59% and 22.11%, respectively, even if the residential customer class increases from 10.79% to 11.32%, in order to help these large employers retain jobs. In my view, merit exists in the proposition that a residential customer is better off with a job and a monthly electric bill that is 48¢ higher, than unemployed with a bill that is 48¢ per month lower.

Finally, CIGFUR and Nucor note that both the Company and the Public Staff, a consumer advocate, testified that they would not oppose a policy decision by the Commission to adopt the alternative proposal.

A countervailing consideration is that under the CIGFUR and Nucor proposal the LGS customer rate class is allocated even more of the fuel cost increase than the 6VP class. Many of the arguments in support of the alternative proposal would also seem to apply to the LGS class. In addition, from a practical and procedural standpoint, should I dissent, the Order would become a recommended order and final rates would not become effective on January 1, 2009. Therefore, in spite of my reservations, I have decided to concur with the Commission's decision on this issue.

In future fuel charge adjustment proceedings, I will, of course, remain open-minded and objective to arguments in favor of charging different fuel riders to recognize and allocate changes in fuel costs if supported by the preponderance of evidence in the record as a whole if such fuel riders are not unreasonably discriminatory.

/s/ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

DOCKET NO. E-7, SUB 710
DOCKET NO. E-2, SUB 847

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 710		
In the Matter of Request by Duke Energy Carolinas, LLC for Approval of a Levelized Billing Program	)	
DOCKET NO. E-2, SUB 847	)	ORDER RULING ON FIXED PAYMENT PROGRAMS
In the Matter of Request by Progress Energy Carolinas, Inc. for Approval of a Balanced Bill Program	)	

BY THE COMMISSION: Each of these dockets concerns voluntary monthly fixed payment programs for residential electric customers. The Fixed Payment Program plan (FPP) of Duke Energy Carolinas, LLC (Duke), was approved by Commission Order dated July 17, 2002, in Docket No. E-7, Sub 710. The Balanced Bill Payment Plan (BBP) of Progress Energy Carolinas, Inc. (PEC), was approved by Commission Order dated February 26, 2004, in Docket No. E-2, Sub 847.

On August 21, 2007, the Commission issued an Order in these dockets for the purpose of investigating the impact of Duke's FPP and PEC's BBP on energy conservation and peak demand. The Order noted that, when Commission approval of these programs was originally requested, certain intervenors expressed a concern that these programs might lead to a lack of conservation by program participants. In addition, the Order also noted that Duke filed a request to revise its FPP on June 8, 2007. In the Staff Conference agenda item which presented this requested revision to the Commission for its consideration, the Public Staff stated that "FPP reports have indicated that, on average, customers who have enrolled in this Program during the first couple of years have increased their energy usage and their contributions to the peak demand at higher levels than a typical residential customer." The Order stated that, given the fact that these programs now have a history of operation and in view of recent legislative developments, the Commission believes it is appropriate to investigate the impact of these programs on energy conservation and peak demand. Therefore, the Order required Duke and PEC to file comments and any studies on the impact of these programs on energy conservation and peak demand by September 21, 2007, and allowed intervenors to file reply comments by October 22, 2007.

The following sections of this Order present the procedural history of these dockets since the issuance of the August 17, 2007 Order; a summary of the comments of the parties; and the conclusions of the Commission.

PROCEDURAL HISTORY

On September 6, 2007, the Attorney General filed a notice of intervention pursuant to G.S. 62-20.

On September 20, 2007, the North Carolina Waste Awareness Network, Inc. (NC WARN) filed a motion to intervene that was granted by Commission Order dated September 28, 2007.

PEC and Duke filed comments on September 20, 2007, and September 21, 2007, respectively.

On October 22, 2007, the Attorney General filed reply comments. On that same date, the Public Staff filed a motion for an extension of time until October 25, 2007, for itself and all intervenors to file reply comments. The Commission granted the Public Staff's motion by Order dated October 23, 2007.

On October 25, 2007, the Public Staff filed its reply comments. NC WARN also filed reply comments on October 26, 2007.

On November 2, 2007, Duke filed a motion requesting that it be permitted to file rebuttal comments to the reply comments of the Public Staff, the Attorney General, and NC WARN by November 9, 2007. The Commission granted Duke's motion by Order dated November 5, 2007. On November 7, 2007, PEC also sought approval to file rebuttal comments.

On November 9, 2007, Duke and PEC each filed rebuttal comments.

COMMENTS

DUKE: In its comments, Duke noted that it requested Commission approval of the FPP program in 2002 based upon industry data indicating that certain customers highly value a payment option with bill amount certainty. According to Duke, the key benefits of the FPP are the certainty of a fixed bill amount for twelve months, irrespective of weather; the peace of mind that results from knowing there will not be a settle up in the twelfth month; and, for customers on the Automatic Payment Plan (bank draft), the convenience of knowing the exact amount drafted each month. Duke launched its FPP program in the summer of 2002. Over 110,000 North Carolina customers participate in FPP, which represents approximately 7.5% of the residential class. Duke stated that the impacts of the FPP program on energy conservation and system peak demand are in the range predicted when the FPP program was initially approved and are consistent with Duke's Equal Payment Plan (EPP), which has been in place since 1958.

Duke asserted that its FPP program provides customers with a highly valued billing option. Duke reported that nine renewal campaigns have produced response rates ranging from 83% to 95%, with an average of 90% for all campaigns. Market research studies conducted in 2004 and 2007 indicated that FPP customers have a high level of satisfaction with this program and a higher level of satisfaction with Duke than customers not participating in FPP.

Duke pointed out that the Commission Order approving the FPP concluded that the potential impact of the FPP on energy conservation did not appear to go significantly beyond that experienced under the EPP, a payment plan to which no party objected. Duke stated that any levelized billing program, either with a true-up, such as the EPP, or without a true-up, such as the FPP, can result in increased usage by the customer as the price impact of increased usage is delayed.

At the inception of FPP, Duke relied on its EPP usage data in order to estimate the increased usage for FPP customers. Then Duke began capturing actual FPP usage data in order to estimate increased usage for purposes of developing customers' monthly fixed payments. Usage adders have been adjusted based on trends shown in the data. Duke furnished the following table which shows the factors (in percentages) currently in use for developing customers' monthly fixed payment amounts. The adders are designed to capture the increased usage and to compensate the Company for the increased risk associated with accepting a fixed payment amount.

	Year on FPP			
	1	2	3	4 or More
Usage Adder	5.00%	4.0%	0.0%	0.0%
Normal Growth	0.30	0.3	0.3	0.3
Price Response Factor	1.66	1.7	1.7	0.0
Subtotal	6.96	5.96	1.96	0.30
Value Risk Factor	2.16	2.16	2.16	2.16
Total FPP Adder (Rounded)	9.1%	8.1%	4.1%	2.5%

The Company stated that it has also compared the actual metered usage data of FPP customers to predicted usage data (based on actual weather experience) in order to approximate the increased usage that is anticipated due to the existence of a fixed monthly payment. The data was gathered from eight enrollment campaigns involving twenty 12-month periods. The usage data was adjusted to exclude the impact of changes due to temperature, but included what would be considered normal growth in customer usage. The average increased usage for Duke's FPP customers developed from this data is presented in the following table.

Usage Increase – Actual vs. Predicted	Percent Increase
Year 1 on FPP	9.3%
Year 2 on FPP	2.9%
Year 3 on FPP	1.3%

Duke opined that this data demonstrates that, as predicted and as seen with EPP customers, FPP customers on average have increased their energy usage somewhat in the first couple of years on the program; however, this trend quickly declines as customers remain on the program.

Duke reported that it has also gathered data related to the impact of FPP on peak demand. Load research data was gathered for a statistical sample of FPP customers and compared to a control group of customers with similar load profiles. The Company found that the FPP sample population indicates a higher usage at peak times than the control group. However, Duke stated that the overall impact on the Company's peak is insignificant given that the kWh sales to customers on FPP are about 2% of Duke's total kWh sales. In 2004, the FPP sample population showed 31% higher usage than the control group, which would affect the system peak by about 0.3%. Further, Duke stated that this trend has declined year by year. In 2006, the FPP sample population showed 11% higher usage, which would affect the system peak by 0.2%. Because a residential customer's air conditioning is likely to be operating continuously during the hours around the summer peak, it seems improbable to Duke that an FPP customer uses more energy at peak times than a non-FPP customer. Duke submitted that the impact on peak demand implied by the data described above may also be attributable to unidentified differences between the FPP sample and the control group.

Duke added that it is exploring options that capitalize on the appeal of FPP while delivering energy efficiency results. Initial customer research shows that energy efficiency options packaged with a fixed bill increases customer interest in such energy efficiency programs and would be likely to increase the level of customer participation in such programs. Duke plans to look for opportunities to combine FPP with energy efficiency options, thereby increasing the likelihood of participation in Duke's overall energy efficiency efforts and increasing energy conservation on the part of FPP customers.

In summary, Duke believes that the FPP is a voluntary billing option with exceptionally high customer satisfaction. The FPP has an effect on usage similar to that occurring under the Company's EPP and, on average, causes increased usage within expected limits during the early years of FPP participation without significantly impacting system peak demand. Duke stated that it will continue to evaluate the opportunity to couple FPP with energy efficiency options. Therefore, Duke submitted that it should continue to offer this valued billing option to its North Carolina retail customers.

PEC: PEC noted that it introduced its BBP in 2004 because industry data indicated that customers highly valued the bill certainty provided by this type of payment option. In addition, PEC submitted that industry evidence showed that customers like a guaranteed billing option and are willing to pay a fee for that guarantee.

In PEC's comments concerning increased usage, PEC stated that it routinely compares the actual and predicted usage of BBP participants (although a formal study was not available). PEC predicts participant usage based upon the most recent 24 months of a customer's usage, adjusted to reflect normal weather. PEC furnished the following table which compares predicted usage to actual usage during the program year for all completed 12 month contract terms:

Participant Year	Enrollment	% Change from Predicted Usage
First	76,213	6.94%
Second	47,242	2.99%
Third	22,285	1.68%

PEC explained that, because the table above shows changes based upon 24 months of usage to determine predicted usage, the percentage changes shown in the table do not represent a true change in annual consumption resulting from the availability of the BBP. According to PEC, the expected increase in usage after three years of participation in the BBP equals 8.6%. PEC stated that the 8.6% expected increase in usage is consistent with PEC's experience with its EPP.

Concerning the impact of its BBP on peak demand, PEC stated that it does not have any relevant data. In creating the BBP, PEC discussed the impact of the program on peak demand with its consultant and concluded that the BBP would not have a significant impact on peak demand. PEC's consultant explained that the primary lifestyle change customers implement when moving to a fixed payment plan is to adopt more comfortable HVAC settings. However, on the peak day when outdoor temperatures approach or exceed 100 degrees, a customer's air conditioning system is operating continuously regardless of whether the thermostat is set at 78 or 75 degrees. Therefore, the impact on the utility's demand does not change. According to PEC, its consultant's view was based primarily on load research conducted by Georgia Power, which concluded that their customers' demand contribution to the system peak hour was virtually the same before and after the customers received the fixed bill payment option. PEC also reported that it had recently spoken with representatives of Gulf Power and that Gulf Power's research had led to the conclusion that there is minimal impact on system peak demand due to the availability of a fixed payment plan option. Based on the information received from its consultant and the results of studies conducted by Georgia Power and Gulf Power, PEC does not believe that its BBP option has a significant impact on the system peak demand.

PEC also stated that nearly 95% of BBP participants elect to continue the plan when renewal contracts are offered and that such a high renewal rate indicates customer satisfaction with the bill certainty associated with this type of service. In addition, a consultant hired by PEC to conduct telephone surveys in 2005 and 2006 to assess customer satisfaction with the BBP concluded that the program achieved an overall satisfaction rating of 87% in 2006. That consultant also concluded that overall satisfaction was so high that there is little room for improvement in the program. PEC has also found that the offering of diverse products and services is viewed positively by customers. While products such as electronic billing, bank drafts, Green Power, credit card payments, outdoor lighting or fixed payment plans do not appeal to all customers, PEC asserted that many customers highly value such products and view PEC positively for offering them.

PEC reported that it encourages all BBP participants to practice conservation in order to reduce their future BBP payments. This is accomplished by providing an "Energy Conservation" fact sheet to all participants at the time that PEC acknowledges the customer's request for BBP service. Additionally, PEC advises the customer by letter and sends the same fact sheet if a customer's usage exceeds predicted levels by 30% or more for three consecutive months in order to help the customer avoid automatic removal from the BBP. PEC is also engaged in developing new demand side management (DSM) and energy efficiency (EE) programs to encourage customers to shift load and reduce energy. In PEC's opinion, the high level of customer satisfaction with the BBP gives customers greater confidence in other PEC programs, such as DSM and EE, so that PEC believes that BBP will be an excellent marketing channel to more effectively meet its customers' overall energy requirements.

In summary, PEC believes that levelized payment plans, such as the BBP or the EPP, do cause a customer to initially increase usage for one to three years, but do not significantly increase the system peak demand. PEC submitted that the BBP is a highly valued payment option for over 55,000 customers in North Carolina representing over 5% of residential accounts. Renewal rates indicate that nearly 95% of participants request to remain on the program after the first year, highlighting their overall satisfaction with the plan. PEC also anticipates that offering the BBP will enhance customer acceptance of other utility programs, such as future DSM and EE offerings. Overall, PEC concludes that the BBP meets customer needs with only minimal impact on generation additions and should continue to be offered.

REPLY COMMENTS

ATTORNEY GENERAL'S OFFICE: The Attorney General's Office (AGO) stated that it understands that Duke's FPP customers and PEC's BBP customers enjoy the certainty of knowing that their electric bill will be the same each month irrespective of the amount of electricity they use. However, the AGO believes that the Commission should discontinue these fixed payment plans for two reasons. First, the FPP and BBP result in increased usage of electricity without providing any significant benefit beyond that which is available under the EPPs. Second, the FPP and BBP are contrary to the Commission's goal of promoting energy conservation.

The AGO believes that the EPPs offered by Duke and PEC provide customers with essentially the same budgeting tool as the FPP and BBP. However, the AGO contended that the effects of the two billing plans on conservation are quite different. According to the AGO, the FPP or BBP customer is automatically paying for increased usage as part of the tariff and there is no yearly true-up. Conversely, an EPP customer will very obviously pay in month twelve for increased usage if the EPP customer does not conserve. The AGO believes that EPP customers have far more incentive to conserve since they can avoid a large true-up payment, or even receive a true-up credit, in month twelve.

The AGO also noted that both Duke and PEC asserted that the effects of the FPP and BBP on peak demand are negligible because all customers run their air conditioning continuously on hot days. However, the AGO believes that a utility's demand is affected by each consumer's choice of thermostat settings. The AGO furnished an example in which an EPP customer sets a thermostat at 78 degrees while an FPP or BPP customer sets a thermostat at 75 degrees. Using this example, the AGO submitted that when the EPP customer's house temperature reaches 78 degrees, the air conditioning turns off and the EPP customer endures a bit of discomfort because lowering the thermostat will cost the EPP customer at the time of the 12-month true-up. Conversely, when the FPP or BBP customer's house temperature reaches 78 degrees, the air conditioning continues to operate until the house temperature reaches 75 degrees, because the FPP or BBP bill will be the same in month twelve even if the customer conserves electricity. Therefore, the FPP or BBP customer continues contributing to the peak demand.

The AGO also contended that the FPP and BBP are inconsistent with public policy. The AGO first cited G.S. 62-2(a)(3a), pursuant to which electric utilities have a duty to give energy efficiency and conservation equal consideration with generation options in meeting their customers' needs. The AGO also cited G.S. 62-155, under which the Commission is required to set rates in a manner that promotes conservation. In the 2005 IRP proceeding, Docket No. E-100, Sub 103, the Commission concluded in its Order dated August 31, 2006, that there is a need for a renewed focus on energy efficiency and conservation. According to the AGO, the Commission's Order was based largely upon the testimony of over one hundred consumers and the general agreement among the parties that rising fuel costs, the prospect that additional baseload generation would be needed, and heightened environmental concerns have brought about the need for more attention to DSM, energy efficiency, and conservation as alternatives to building new generating facilities. Finally, the AGO cited Senate Bill 3 as the most recent public policy statement on the need for all consumers to conserve electricity. However, the AGO argued that the FPP and BBP send the opposite message because those programs tell customers that if they have the money to pay a monthly fixed amount, they need not be concerned with conservation. Therefore, the AGO stated that the Commission should correct this inconsistency by closing the FPP and BBP.

In summary, the AGO recommended that the Commission should require Duke and PEC to close the FPP and BBP to new customers and phase customers off of these programs over a time period that the Commission finds reasonable.

NC WARN: NC WARN recommends that the FPP and BBP be discontinued because these programs encourage customers to increase their usage of electricity. NC WARN believes the basic problem with these programs is that they do not provide customers with any feedback about their electricity use that encourages them to use less electricity. NC WARN stated that the increased use by customers in these programs has been documented in this case and that customers in these programs simply use more electricity than do other customers. While NC WARN acknowledged the popularity of these programs, it stated that such popularity does not translate into a positive policy that benefits the customers, the utilities or the State in general.

NC WARN took the position that the FPP and BBP are demand increasing programs (DIP) and are contrary to the Commission's clear mandate to promote energy conservation. According to NC WARN, any program that increases electricity sales should be closely scrutinized by the Commission under G.S. 62-2(a)(3a) to determine if any positive factors outweigh the negative ones. NC WARN believes that eliminating DIPs like these would have a direct and significant impact on the need to build new power plants.

Given the focus of several recent Commission dockets concerning energy efficiency and the mandate of Senate Bill 3, NC WARN stated that here is one opportunity for the utilities to eliminate demand without causing ratepayers any increase in their bills. The monthly service charge and fees for risk associated with these programs are designed to recover the actual costs of the programs.

NC WARN added that it fully agrees with the AGO's comments. Therefore, NC WARN recommended that the Commission require the utilities to close the FPP and BBP to new customers and phase out existing customers as soon as possible.

PUBLIC STAFF: The Public Staff stated that it was not surprising that FPP and BBP participants are very well satisfied with these programs because they enable customers to hedge against the risks of adverse weather and to increase their electrical usage at no short-term cost.

The Public Staff also stated that it disagreed with Duke and PEC that FPP and BBP participants use no more energy at the peak than other customers. According to the Public Staff, utilities often assert that air conditioning units run continuously at the peak, but common experience shows that this assertion is incorrect. The Public Staff claimed that an air conditioner runs continuously at the peak only in unusual situations, such as when a unit is undersized. Moreover, the Public Staff pointed out that a utility's residential load at system peak does not consist entirely of air conditioning. Customers use other appliances at the time of peak. The Public Staff added that, after reviewing the peak usage studies cited in Duke's comments, and comparing those studies to data submitted by Duke in its annual reports on the FPP to the Public Staff and the AGO, the Public Staff believes that a reasonable range of increased peak usage for FPP participants on a going forward basis is from 10% to 20%. Although PEC has not conducted any studies of BBP participants' peak usage, the Public Staff believes it is reasonable to assume that their usage patterns are generally similar to the FPP participants of Duke.

Concerning the annual usage of FPP and BBP participants, the Public Staff noted that Duke and PEC stated that the typical first-year FPP and BBP participant experiences an increase of 7% to 9% in annual usage over the preceding year, and in subsequent years, usage by participants continues to increase, but at a slower pace. The Public Staff reported that Duke had advised the Public Staff that the average third year FPP customer's usage is about 9.9% higher than the customer's usage before the year he or she joined the program. Similarly, PEC stated that the typical increase in usage after three years of BBP participation is about 8.6%. After its review of the utilities' comments, the Public Staff concluded that the usage increases estimated by Duke and PEC appear to be reasonable.

In summary, the Public Staff stated that it is aware of the widespread acceptance of the FPP and BBP and their usefulness as a hedging mechanism for customers. Nevertheless, in the Public Staff's view, these programs are no longer appropriate and should be terminated. According to the Public Staff, the General Assembly and the people of the State have become increasingly concerned about the need to conserve electric power and minimize emissions of pollutants and greenhouse gases. Further, the Commission has encouraged the utilities to increase their energy efficiency efforts, and much of the impetus for this encouragement has come from the utilities themselves. The Public Staff also cited Senate Bill 3, which declares that it is the policy of the State "[t]o promote the development of renewable energy and energy efficiency." The Public Staff believes it would be inconsistent to allow the continuation of programs that have the effect of encouraging increased electric usage at a time when the Commission is pushing the State's utilities to develop new energy conservation programs. Therefore, the Public Staff recommended that the FPP and BBP be closed to new customers; that existing agreements relating to participation be allowed to continue into effect, but not be renewed or extended beyond their current terms; and for any further relief the Commission may deem just and proper.

REBUTTAL COMMENTS

DUKE: In its rebuttal comments, Duke requested that the Commission not discontinue the FPP billing option, as recommended by the AGO, NC WARN and the Public Staff, and urged the Commission to allow the Company to continue to make that option available to the customers who highly value a payment option with bill amount certainty. Duke stated that the program renewal rates clearly show that customers electing to participate in FPP are extremely satisfied with the program.

In response to the AGO's position that the FPP signals customers that they need not be concerned with conservation, Duke stated that it has always been clear that any levelized billing program, either with a true-up (the EPP) or without a true-up (the FPP), can result in increased usage by the customer because the price impact of increased usage is delayed. Duke argued that the AGO and NC WARN are simply incorrect in implying that a FPP customer has no incentive to conserve electricity, because an FPP customer's fixed payment amount for the next year is based on the customer's usage in the prior period.

Contrary to NC WARN's characterization of the FPP as a demand increasing program, Duke characterized the FPP as a customer billing option, such as the EPP. Further, Duke stated that its comments demonstrated that the impact of the FPP on system peak is minimal and that NC WARN's claim that eliminating this option would have a direct and significant impact on the need to build new power plants is also incorrect.

Duke agreed with the intervenors that energy efficiency and conservation must be taken into consideration in meeting customers' energy needs and that there is heightened concern in this regard. Duke stated that it has increased its efforts in this area as evidenced by its request for approval of a new energy efficiency plan in Docket No. E-7, Sub 831. However, Duke believes that promoting this policy goal need not be at the expense of providing customers with valued options such as the FPP. Rather than accept the tyranny of "either/or", Duke reported that it is exploring options that capitalize on the appeal of the FPP while delivering energy efficient results. As noted in its earlier comments, Duke stated that it will look for opportunities to incorporate FPP with energy efficiency options. Therefore, Duke requested that the Commission consider delaying any decision that would discontinue the FPP billing option until resolution of matters related to the proposed energy efficiency plan in Docket No. E-7, Sub 831.

PEC: PEC stated that it offers the BBP because its customers indicated a strong desire for this service. PEC now has over 62,000 customers subscribing to the BBP.

According to PEC, the issue before the Commission is whether this customer option should be eliminated because it may result in incremental increases in electricity usage. PEC believes that a thorough evaluation makes it apparent that the potential of the BBP for causing incremental increases in electricity usage is not a valid basis for depriving 62,000 customers of this service. PEC also stated that a service offering that improves the utility's load factor is desirable because it allows the utility to provide more efficient and economical service. Furthermore, PEC stated that it has several other tariffs that arguably result in incremental electricity usage, including its declining block rate tariffs, the Large General Service Real Time

Pricing tariff, and its economic development rate tariffs. PEC submitted that all of these tariffs meet important customer needs, just like the BBP tariff, and should not be withdrawn.

PEC believes that the BBP should not be terminated if meeting customer needs and customer satisfaction are important goals.

CONCLUSIONS

The Commission Order issued in this proceeding on August 17, 2007, required Duke and PEC to file comments and any studies on the impact of these programs on energy conservation and peak demand.

With respect to the impact of these programs on energy conservation, Duke's filing shows that FPP customers increase energy usage on average by 9.3% in the first year, 2.9% in the second year, and 1.3% in the third year as compared to predicted energy usage. PEC's filing shows that BBP customers increase energy usage by 6.94% in the first year, 2.99% in the second year, and 1.68% in the third year as compared to the predicted level of energy usage. Thus, based on the studies of Duke and PEC, the average FPP or BBP customer increases energy usage approximately 7% to 9% in the first year of participation. However, the increases in usage decline in the second and third years of participation. The average increase in usage in the third year of participation is approximately 1% to 2% over the predicted level of usage. Overall, PEC stated in its comments that the average increase in usage after three years of participation in the BBP is approximately 8.6% and, according to the comments of the Public Staff, Duke has stated that the average third year FPP participant's usage is about 9.9% higher than the usage in the year before the customer enrolled in the FPP. The Public Staff also stated that the usage increases estimated by Duke and PEC appear to be reasonable.

Concerning the impact of these programs on peak demand, Duke reported that load research data gathered for a statistical sample of FPP customers and compared to a control group showed that FPP customers had 31% higher usage at peak than the control group in 2004. Duke also reported, however, that this trend has declined year by year and that, in 2006, the FPP sample showed 11% higher usage. Further, Duke stated that the impact on peak demand implied by the data may be attributable to unidentified differences between the FPP sample and the control group. PEC stated that it has no data regarding the impact of its BBP on peak demand. Both PEC and Duke believe it is improbable that FPP or BBP customers use more energy at peak than other residential customers because they believe air conditioning units run continuously at peak. The Public Staff does not believe air conditioning units run continuously at peak, except in unusual situations, and noted that a utility's residential load at peak consists of more than air conditioning. Based upon its review and Duke's data and studies, the Public Staff believes that a reasonable range of increased peak usage for FPP participants on a going-forward basis is from 10% to 20% and that it is reasonable to assume a similar usage pattern for PEC's BBP participants.

Both Duke and PEC acknowledge that customers in these programs initially increase energy usage, but they believe that these voluntary billing options should continue to be offered. Duke reported that over 110,000 of its North Carolina customers are currently enrolled in the

FPP, and PEC reported that it now has over 62,000 customers subscribing to the BBP. The utilities believe that renewal rates in excess of 90% and marketing research indicate exceptionally high customer satisfaction with these programs. Both Duke and PEC also submit that these programs could be coupled with EE or DSM initiatives and believe that the high level of customer satisfaction associated with these programs could increase customer acceptance of a combined offering.

The AGO, NC WARN, and the Public Staff argue that these programs should be closed to new customers and phased out for existing customers. The AGO stated that these programs result in increased energy usage without providing any significant benefit to customers beyond that which is available under the EPP and that these programs are contrary to the Commission's goal of promoting energy conservation. NC WARN agrees with the AGO and added that the popularity of these programs does not translate into a positive policy that benefits customers, the utilities or the State in general. NC WARN believes that the basic problem with these programs is that they do not provide customers with any feedback about their electricity use that encourages them to use less electricity. The Public Staff believes that the usage increases estimated by Duke and PEC for the FPP and BBP are reasonable and that the same factors which cause participants to increase their overall usage would similarly lead them to increase their usage at peak times. Despite the widespread acceptance of the FPP and BBP, the Public Staff believes these programs are no longer appropriate in light of the enactment of Senate Bill 3 and the fact that the Commission has expressed interest in new energy conservation programs and that they should be terminated.

After careful consideration of the entire record in this proceeding, the Commission concludes that the FPP and the BBP should be closed to all customers who are not enrolled in, or have not made application to participate in, these programs as of the date of this Order, but that Duke and PEC should be allowed to indefinitely continue to offer these programs for the limited purpose of allowing renewals by participants who were enrolled or had applied to participate in these programs at the time of closure. The Commission has reached this conclusion in an attempt to balance its obligation to encourage appropriate energy efficiency, conservation and demand side management efforts, G.S. 62-2(a)(3a), (4), and (10), on the one hand, and its obligation to ensure the implementation of just, reasonable and economical rates for consumers, G.S. 62-2(a)(3) and (4), on the other.

The undisputed information in the record establishes that customers that have opted to participate in the FPP and BBP programs have a high degree of satisfaction with this billing option. Although most customers taking service under the FPP and BBP likely pay a higher per unit charge than customers taking service under more traditional rate schedules as a result of the inclusion of a risk factor and an administrative fee in the development of the annual fixed payment amount, these additional payments compensate the utilities for the additional risks they face as a result of the existence of the programs, and the Commission has previously concluded that these fees are just and reasonable. Before a customer begins to take service under these programs, he or she is given an estimate of his or her proposed fixed payment amount and information concerning his or her past bills. At the end of each contract period, the utilities provide each customer with the updated fixed payment amount and a statement of the amounts he or she would have paid under more traditional rate schedules. As a result, a customer electing to participate in these programs should be well aware of the fact that he or she is paying a premium for the opportunity to participate in these programs, effectively eliminating any concern that the FPP and BBP schedules unfairly overcharge customers compared to more traditional rate schedules. Thus, there is no reason for the Commission to reject the utilities' claims that participating customers are highly satisfied with the FPP and BBP, and we conclude that this fact should be taken into consideration in deciding these dockets. However, the fact that customers like the FPP and BBP is not conclusive in light of the countervailing considerations that the Commission must take into consideration as well.

All information submitted in this proceeding shows that FPP and BBP participants increase electric usage during the initial three years of enrollment. In addition, the record suggests that program participation may be associated with increased peak demand as well. As the AGO, NC WARN, and the Public Staff have correctly pointed out, the General Assembly and the Commission have placed increased emphasis on the importance of energy efficiency, conservation, and demand side management as a solution for the challenges resulting from higher fuel and other input prices, increasing demand and the potential need for the construction of new generating facilities. The factors that have led to this increased emphasis on energy efficiency, conservation and demand side management have become much more pronounced than they were at the time that the FPP and BBP were initially approved. In fact, this change in circumstances is the reason that the Commission undertook a review of the FPP and BBP in this proceeding. In addition, we now have evidence of the actual nature and extent of the impact of the FPP and BBP on customer consumption and peak demand. Upon carefully weighing the information in the present record, the Commission concludes that the high level of customer satisfaction with the FPP and BBP programs does not justify the impact on customer energy consumption and peak demand resulting from the addition of new customers to these programs. As a result, the Commission concludes that, given the fact that the FPP and BBP tend to result in increased usage and peak demand by program participants, particularly in the initial year of program participation, and the Commission's desire to encourage cost-effective energy efficiency, conservation and demand side management efforts, the continued availability of the FPP and BPP plans to new participants is not in the public interest and that these plans should be closed to new customers.

The Commission's decision to eliminate the FPP and BBP for new customers does not, however, resolve the question of what should be done about the fact that there are approximately 170,000 satisfied residential customers currently receiving service on these plans. Although the Commission has an obligation to foster cost-effective energy efficiency, conservation and demand side management efforts, it also has a duty to ensure that appropriate options are available to consumers. G.S. 62-133.6(g). As a result, the Commission has to balance the desire of existing customers to remain on these programs with the Commission's interest in facilitating appropriate energy efficiency, conservation and demand side management efforts. In reaching the conclusion that existing program applicants and participants should be allowed to remain on the FPP and BBP, the Commission concludes that the relatively limited increased usage and peak demand associated with service provided to these customers is outweighed by the countervailing policy of allowing utilities to provide desirable service alternatives.

No party to this proceeding has suggested that the mere fact that a rate, tariff or programs results in some degree of increased usage, standing alone, necessitates a decision to eliminate the availability of that rate schedule. Although the record suggests that the long-standing EPP programs offered by both Duke and Progress have effects on customer usage and peak demand similar to that resulting from the FPP and BBP, there has been no call in this proceeding for the elimination of the EPP. On the contrary, the parties to this proceeding seem to uniformly support the EPP. During recent periods of high natural gas prices, the Commission has called on natural gas utilities to expand the availability of EPP programs to assist customers in their efforts to cope with markedly higher bills. While the fact that there is an annual true-up associated with the EPP that is not found in the FPP and BBP might mean that EPP customers have a greater incentive to conserve than customers participating in the FPP and BBP, the present record does not contain any evidence verifying the correctness of this conclusion. As a result, given the similar effect of these plans on customer usage and peak demand and the fact that there have been no challenges to the continued existence of the EPP, the Commission concludes that all parties agree that the mere fact that a particular rate has a tendency to result in increased customer usage or peak demand, standing alone, does not justify the complete elimination of that tariff.

Furthermore, the undisputed evidence suggests that the largest increase in customer consumption under the FPP and BBP comes in the first year of participation. In other words, year by year comparisons of the rate of increase in usage shows that the usage increase is greatest in the first year of participation and that the rate of increase in usage declines in both years two and three. No information on usage beyond the third year was furnished or available. While the exact impact of these programs on peak demand is not as clear, one can safely assume that the same rate of increase pattern would exist with respect to peak demand. Thus, the energy efficiency, conservation and peak demand control benefit that would result from closing the FPP and BBP to new customers is significantly greater than any benefit that would result from ending the FPP and BBP for existing program participants. Any argument to the contrary assumes that existing FPP and BBP customers that return to more traditional rate schedules will reduce their energy consumption to previous levels, a proposition for which there is no support in the record. Any customer that has actual usage that exceeds estimated usage by 30% or more for three consecutive months is subject to removal from the FPP or BBP, so that there is a remedy if an existing customer significantly increases his or her usage while remaining on the FPP or BBP. As a result, by closing the FPP and BPP to new customers, the Commission will have achieved the bulk of the energy efficiency benefits that are available from modification or elimination of the FPP and BPP without depriving existing program customers of the benefits of a program with which they are satisfied.

The record further reflects that there is at least some possibility that the availability of the FPP and BPP can be associated with improved energy efficiency and conservation efforts. Both Duke and PEC indicated that the high levels of customer satisfaction associated with the FPP and BPP could provide a platform for enhanced energy efficiency, conservation and demand side management efforts. In allowing existing customers to stay on the FPP and BPP, the Commission concludes that Duke and PEC should explore the prospects for combining the FPP and BPP with enhanced energy efficiency, conservation and demand side management efforts and file a report with the Commission within six months from the date of this Order updating the Commission about the status of this effort and proposing the adoption of any FPP or BPP-related energy efficiency, conservation or demand side management programs that should be considered in conjunction with the continued availability of the FPP and BPP to existing customers.

In addition, the effect of the Commission's decision to allow existing FPP and BPP participants to remain on those schedules after they are closed to new customers is tantamount to a phase-out of these two programs. Although renewals will be allowed on a grandfathered basis, as participants decide not to renew participation, move out of the service areas, or move to different residences or dwelling units within the service areas, any impact of these programs on usage and peak demand will be reduced and eventually eliminated. Although the proponents of eliminating the FPP and BPP have urged the Commission to remove existing customers from the programs, all of them recognize the need for an appropriate transition mechanism for the 170,000 customers currently taking service under these programs. The Commission's decision to allow existing customers to remain on these programs until they are no longer eligible or no longer wish to participate is a transition mechanism that differs from the approaches urged by the AGO, NC WARN, and the Public Staff only insofar as it provides for a longer transition period than each of them thought to be appropriate.

In summary, the Commission believes this decision is fair and reasonable; that it will promote harmony between Duke, PEC, and their consumers; and that it is consistent with the full range of policy objectives that the General Assembly has instructed the Commission to implement. The Commission believes that the result reached in this proceeding represents a fair balance between the need to encourage energy efficiency, conservation and demand side management and the need to provide customers with rate schedules which serve their interests. As a result, the Commission concludes that Duke's FPP and PEC's BPP should be closed to new customers and that existing customers, including customers who have made application to participate in these programs as of the date of this Order, should be allowed to remain on the FPP and BPP until those customers either elect to refrain from, or become ineligible to continue, participating in these programs.

IT IS, THEREFORE, ORDERED as follows:

1. That the Fixed Payment Program tariff of Duke and the Residential Balanced Bill Payment Plan tariff of PEC shall be closed to new participants effective as of the date of this Order;

2. That Duke and PEC shall be allowed to continue to offer these programs on a grandfathered basis for the limited purpose of renewals by participants who had enrolled in or applied to participate in these programs as of the date of this Order;

3. That Duke and PEC shall file a report with the Commission within six months of the date of this Order updating the Commission concerning their efforts to develop programs that work in conjunction with the Fixed Payment Program and the Balanced Bill Program to encourage energy efficiency and conservation by customers continuing to take service under those tariffs; and

4. That Duke and PEC shall continue to file and provide the program reports required by the previous Commission Orders in these dockets.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of March, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

mr031408.01

Commissioners Robert V. Owens, Jr., Lorinzo L. Joyner, and William T. Culpepper, III concur in part, but dissent with respect to the Majority's decision to allow renewals by participants in these programs.

DOCKET NO. E-7, SUB 710
DOCKET NO. E-2, SUB 847

Commissioners Lorinzo L. Joyner and Robert V. Owens, Jr., Concurring in Part and Dissenting in Part: We concur with the decision to close Duke's Fixed Payment Program plan and PEC's Balanced Bill Payment plan to new participants. However, we dissent from the Majority's decision to allow Duke and PEC to continue to offer these programs to current participants indefinitely, on a grandfathered basis. Instead of allowing customers to renew enrollment in these programs, we believe that the Commission should have required that existing agreements between Duke and PEC and their customers be terminated at the end of their current terms.

The information filed in these dockets clearly shows that these programs cause increased usage and higher peak demands which are contrary to the public policy goals of promoting energy efficiency and conservation.[1] While the Commission's decision to close these programs to new participants will allow Duke and PEC to avoid the highest increase in usage that has been shown to occur in the first year of participation, the negative impact of these programs is not limited to the initial year of participation. According to the record, participants also continue to increase usage in years two and three, by 3.0% and 1.5%, respectively. Further, Duke's load data for 2006 indicates that FPP customers have 11% higher usage at time of peak and the Public Staff believes that a reasonable range of increased peak usage by participants in these programs on a going-forward basis is from 10% to 20%. Given this evidence, we are hard pressed to understand why the Majority has opted to allow Duke and PEC to offer 170,000 customers renewals in these programs, especially in the face of opposition from of all the consumer representatives that intervened in these dockets.

[1] The importance of these goals has been re-emphasized in recent legislative enactments, which served as the impetus for the Commission, on its own motion, to institute the instant investigation. See Order Requesting Further Information, issued 21 August 2007, in Docket No. E-7, Sub 710, and E-2, Sub 847. ("In view of recent legislative developments, the Commission believes it is appropriate to investigate the impact of Duke's FPP and Progress' BPP on energy conservation and system peak demand.")

The Majority stresses the popularity of the programs and contends that its decision to permit Duke and PEC to allow renewals their current FPP and BPP customers is tantamount to phasing them out over time. We find absolutely nothing in the Majority Order that causes a phase-out. Before and after the Majority's decision, existing program participants control when and if their participation in the programs ends. So long as a participating customer does not voluntarily leave the program, does not move out of the service area or does not move to a different dwelling, he may continue in the program indefinitely.

We appreciate the fact that participating customers value the opportunity to enroll in these plans and that virtually all of them respond positively to the Companies' renewal campaigns. Under different circumstances we would likely support their ability to continue to enroll and renew. However, the promotion of energy efficiency and conservation are declared public policy goals that appear throughout Chapter 62 of the North Carolina General Statutes. Having first concluded as a matter of public policy that these programs should be closed to new applicants, the Commission was then required to balance the promotion of energy conservation and the desires of 170,000 customers. Because we do not believe that the programs' popularity, standing alone, transformed them from bad public policy into good public policy, we think that the balance struck by the Majority missed the mark. If the negative impacts of these programs necessitated their closure to new participants, then those same negative impacts should have compelled the Commission to prevent indefinite renewals.

/s/ Lorinzo L. Joyner
Commissioner Lorinzo L. Joyner

/s/ Robert V. Owens, Jr.
Commissioner Robert V. Owens, Jr.

DOCKET NO. E-7, SUB 710
DOCKET NO. E-2, SUB 847

Commissioner William T. Culpepper, III, concurring in part and dissenting in part:

I can certainly understand and appreciate the reasoning behind the Majority's decision to allow the continuation of the FPP and BPP programs on a grandfathered basis, because this represents a middle-ground compromise between the positions of the parties to these dockets. However, I am of the opinion that a decision that allows these programs to continue indefinitely with respect to over 170,000 existing residential customers plus some unknown number of new customers who have applied to participate in these programs as of the date of this Order is effectively at odds with the current public policy of this State (as recently espoused by our General Assembly's enactment of Senate Bill 3) that has led this Commission to unanimously conclude that the subject programs should be closed to new participants. Moreover, I am of the belief that the customer satisfaction elements cited by Duke and PEC in their comments can also be achieved by properly designed EPP programs. In this regard, I am of the opinion (having not been convinced otherwise by the record before the Commission in these dockets) that the EPP program sends more appropriate price and energy conservation signals to the residential customer than do the FPP and BPP programs.

Therefore, while I concur with all of the members of the Commission in closing the FPP and BPP tariffs to new participants, I dissent from the Majority's decision to allow a continuation of these tariffs for existing participants and applicants. I believe that it would have been more in line with current public policy to have adopted the Public Staff's recommendation that existing FPP and BPP agreements be allowed to continue into effect, but not renewed or extended beyond their current terms.

/s/ William T. Culpepper, III
Commissioner William T. Culpepper, III

DOCKET NO. E-2, SUB 916

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Progress Energy Carolinas, Inc., for a Certificate of Public Convenience and Necessity to Construct Approximately 600 MW of Combined-Cycle Generating Capacity at its Richmond County Energy Complex Near Hamlet, North Carolina	)	ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

HEARD: Hamlet City Hall, 201 Main Street, Hamlet, North Carolina, on Thursday, June 26, 2008, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, September 3, 2008, at 9:00 a.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding; Commissioners Robert V. Owens, Jr., and Howard N. Lee

APPEARANCES:

For Progress Energy Carolinas, Inc.:

Len S. Anthony, General Counsel, Progress Energy Carolinas, Inc., Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Dianna W. Jessup, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, P. O. Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: On December 20, 2007, acting pursuant to Commission Rule R8-61, Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC), filed preliminary plans for a new 600 megawatt (MW) combined-cycle generating facility at its Richmond County Energy Complex near Hamlet, North Carolina. PEC's proposed combined-cycle facility would consist of two combustion turbines, each having a heat recovery steam generator. The planned in-service date of the facility is the summer of 2011.

Following through on its Rule R8-61 filing, PEC filed an Application for a Certificate of Public Convenience and Necessity (CPCN) pursuant to G.S. 62-110.1 along with the supporting testimony of Michael Luhrs on April 30, 2008.

By Order issued May 20, 2008, the Commission scheduled a public hearing on this matter for June 26, 2008, in Hamlet, North Carolina and an evidentiary hearing for September 3, 2008, in Raleigh, North Carolina. The Commission also required PEC to give public notice of the application and the scheduled hearings. PEC published notice in a newspaper in Richmond County.

Petitions to intervene were filed by the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) and the Attorney General. The Commission granted both petitions to intervene.

The public hearing in Hamlet, North Carolina was held on June 26, 2008, as scheduled. Kenneth Robinette, Jim Haynes, Richard Conder, and Kenneth Melvin appeared at the public hearing and testified in support of the application.

On August 19, 2008, the Public Staff filed the testimony of John R. Hinton, Thomas S. Lam, and Darlene P. Peedin.

On August 22, 2008, PEC filed a motion to cancel the evidentiary hearing scheduled for September 3, 2008. In that motion, PEC stated that the Public Staff, CIGFUR, and the Attorney General had authorized PEC to represent that they had agreed to waive cross-examination of all witnesses, to stipulate all prefiled testimony and exhibits into the record, and to cancel the evidentiary hearing. On August 27, 2008, the Commission issued an order canceling the evidentiary hearing, admitting pre-filed direct testimony into the record, and requiring proposed orders.

On September 3, 2008, a public hearing was held in Raleigh, North Carolina, as scheduled. No public witnesses testified.

Based on the foregoing, the evidence admitted during the public hearings, and the entire record of this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. PEC is a public utility providing electric utility service to customers in its franchised service area in North Carolina subject to the jurisdiction of this Commission.

2. PEC filed an application for a CPCN for the 600 MW combined-cycle generating facility at its Richmond County Energy Complex on April 30, 2008. The Commission has jurisdiction over the application pursuant to G.S. 62-110.1, which provides that a public utility must obtain a CPCN from the Commission prior to constructing electric generating facilities to be directly or indirectly used for public utility service.

3. PEC's most recent demand and energy forecasts indicate that unless PEC adds additional generation capacity to its system by the summer of the year 2011, its capacity margin will fall to an unacceptable level and PEC will not be able to reliably meet the demand for electricity in its assigned service territory.

4. PEC evaluated purchased power opportunities and self-build supply side resources in determining that the addition of 600 MW of combined-cycle natural gas fired generation at its Richmond County Energy Complex is the most appropriate resource to meet its resource needs by 2011.

5. PEC considered a broad spectrum of demand-side management (DSM) and energy efficiency (EE) programs, as well as renewable resources in its integrated resource planning process and in making the decision to pursue the 600 MW combined-cycle generating facility at its Richmond County Energy Complex. PEC cannot rely upon DSM, EE and renewable resources to eliminate or delay its need for additional intermediate generating capacity in the 2011 time frame.

6. The addition of approximately 600 MW of combined-cycle natural gas fired generation at PEC's Richmond County Energy Complex by the summer of 2011 is the most cost effective and appropriate resource to meet PEC's customers' forecasted electricity needs.

7. PEC conducted a comprehensive siting process before selecting the Richmond County Energy Complex site. Issues relating to the selection of this site were properly addressed.

8. PEC's estimated construction costs for the 600 MW combined-cycle generating facility are reasonable and should be approved. PEC should be required to submit a progress report each year during construction that includes any revisions in the cost estimates as required by G.S. 62-110.1(f).

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

The evidence in support of these findings of fact is found in the Application for a CPCN (the Application) filed on April 30, 2008, the testimony and exhibits in this docket, and the statutes and case law concerning the jurisdiction of the Commission. These findings are informational, procedural, and jurisdictional in nature.

G.S. 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. State ex rel. Utilities Comm. v. Empire Power Co., 112 N.C. App. 265, 278 (1993), disc. rev. denied, 335 N.C. 564 (1994); State ex rel. Utilities Comm. v. High Rock Lake Ass'n, 37 N.C. App. 138, 141, disc. rev. denied, 295 N.C. 646 (1978). A public need for a proposed generating facility must be established before a certificate is issued. Empire, 112 N.C. App. at 279-80; High Rock Lake, 37 N.C. App. at 140. Beyond need, the Commission must also determine if the public convenience and necessity are best served by the generation option being proposed. The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. State ex rel. Utilities Comm. v. Casey, 245 N.C. 297, 302 (1957). The Commission has considered whether the public convenience and necessity are served by the proposal in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

This finding is based on the forecasts contained in PEC's 2007 Integrated Resource Plan, PEC's Application, the testimony of PEC witness Michael Luhrs, and the testimony of Public Staff witness Thomas Lam.

PEC witness Luhrs testified that PEC is experiencing significant customer and usage growth and that this requires the addition of generation resources in order to maintain an adequate capacity margin. He further testified that there are a number of reasons for this growth. North Carolina continues to experience strong population growth, which causes increased demand for electricity. The U.S. Census Bureau projects that North Carolina will become the nation's seventh most populous state in the next two decades, with a population of 12 million people. The Raleigh News & Observer recently reported that the Raleigh area and the Charlotte area are the third and seventh fastest growing metropolitan areas in the United States, respectively. In addition, the average new home size has increased by greater than 50 percent from 1970 to today, and average annual energy consumption per household has increased by a similar amount, from 9,800 kWh in 1970 to 14,200 kWh today.

Mr. Luhrs testified that in addition to meeting expected growth in demand, all utilities require a margin of generating capacity above the capacity used to serve expected load in order to assure reliable service. Periodic outages of generating facilities are necessary in order to perform maintenance, refuel nuclear plants, and repair failed equipment. At any given time during the year, some plants will be out of service and unavailable for these reasons. Adequate reserves must be available to provide for this unavailable capacity and for higher than projected peak demand due to forecasting uncertainty and abnormal weather.

PEC witness Luhrs testified that PEC determines the level of reserves needed to provide an adequate and reliable power supply based on maintaining a target loss of load probability of less than one day in ten years. To achieve this level of reliability, analyses demonstrate that a capacity margin of 11% to 13% is appropriate. He testified that capacity margin is a commonly accepted measure of reserves. Reserves refer to the amount of generation resources, in megawatts, planned to be available in excess of projected load. Capacity margin, expressed as a percent, is derived by dividing the reserves by the planned resources.

Witness Luhrs further testified that the minimum capacity margin of 11% is acceptable in the short term when there is greater certainty relative to load and resources, but a capacity margin target of 12% to 13% is necessary in the longer term to compensate for forecasting uncertainty and potential delays in bringing new capacity additions on-line. This criterion is also used to determine the need for generation additions. Capacity additions are inherently "lumpy," and it is not normally practical to add the exact increment of capacity needed to maintain a capacity margin at the exact targeted level.

Witness Luhrs testified that in order to maintain a capacity margin within the 11-13% range, PEC must add additional generation capacity by the summer of 2011. PEC's projections show total summer demand will grow from 12,640 MW in 2008 to 13,169 MW by 2011. After adjusting for the effects of DSM and EE programs, the net peak demand grows from 12,238 MW in 2008 to 12,398 MW in 2011. This forecast reflects the projected impact of 771 MW of DSM/EE in 2011 which includes incremental DSM/EE of 370 MW forecasted to be achieved relative to 2008 levels.[1] Also, the 2011 forecasted peak demand does not include an existing 100 MW of wholesale load in PEC's control area that PEC currently serves and hopes to serve going forward. The peak demand forecast is based on normal weather and does not reflect weather volatility. On August 9, 2007, during a period of above normal temperatures, PEC set a record summer peak demand of 12,656 MW. This weather event demonstrates the need for maintaining adequate reserves to respond to load, weather, and resource uncertainties in order to provide reliable service.

Exhibit No. 3 to witness Luhrs' testimony is a revision to Table 3-1 from PEC's Commission Rule R8-61 pre-filing based on the 2008 Q2 Update. Table 3-1 shows summer peak load and supply resources with and without the proposed additional generation capacity in 2011. The table also shows that Total Committed Resources for Load in 2011 is projected to be only 13,814 MW compared to the projected peak of 12,398 MW.[2] Revised Table 3-1 demonstrates that, unless PEC adds additional generating capacity, its capacity margin will fall to 10.2% in 2011 and 8.6% by 2012. In the absence of the forecasted and planned 370 MW of new DSM/EE programs, PEC's capacity margin will further decrease to 7.6% in 2011 and 5.0% in 2012. The additional capacity proposed by PEC and the achievement of the 370 MW of additional DSM/EE will increase the capacity margin to 14% in 2011.

PEC's 2007 Resource Plan and 2008 Q2 Update show an undesignated resource in 2010. Comparison of these two plans demonstrates that PEC has made significant progress to acquire this capacity through additional scheduled generator uprates and confirmation of the 2010, 150 MW short term purchase. With these uprates and the continued pursuit of some small purchased power contracts, the 2011 undesignated resource need is expected to be met without building new capacity. However, these contracts will not replace the need for the proposed combined-cycle facility because they only change the capacity margin by approximately 1% and do not allow PEC to achieve the target capacity margin required for 2011 forward.

Witness Luhrs testified that there is a significant resource uncertainty in the 2011 timeframe and beyond resulting from DSM/EE uncertainty, wholesale load forecasts, renewable generation availability, and purchased power opportunities. The actual MWs realized from DSM/EE programs will be impacted by many variables, some of which are beyond PEC's control. He explained that program success will depend on the commitment of customers to participate (programs are voluntary) and the engineering and contractor resources available in the marketplace to deliver these services. With respect to renewable generation, while PEC has received responses to an RFP for firm renewable generation capacity totaling approximately 400 MW, only 37 MW of this 400 MW will be available by 2011.

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[1] Incremental DSM/EE achievements through 2017 total 1000 MW as described in PEC's DSM Plan filed separately in conjunction with PEC's 2007 Resource Plan and included in the 2008 Q2 Update.

[2] The capacity shown in the "Total Committed Resources" line of Table 3-1 includes a 150 MW undesignated power purchase in 2011 and capacity additions previously approved by the Commission (the 2009 combustion turbine addition at the Wayne County facility).

Witness Luhrs concluded that all of these variables create a combined capacity uncertainty of 725 MW in 2011. The 2008 Q2 Update includes 688 MW of this total, which includes everything except the 37 MW of renewable capacity. Significantly, none of the 688 MW included in the resource plan is firm. Even if the 688 MW of capacity were firm, the capacity margin would only be 11.3% without the proposed new generating facility. Given that none of these resources are firm, by the time it is known how much will be firm, it would be too late to take the necessary actions required to build additional capacity, such as permitting, engineering, and construction. See Figure 1-3 of the R8-61 Preliminary Plan filing.

Public Staff witness Lam also testified that in order to maintain an appropriate capacity margin, PEC must add generating capacity by 2011. He testified that in PEC's most recent annual Resource Plan, filed in Docket No. E-100 Sub 114 on December 3, 2007, and in its second quarter 2008 IRP Update dated January 29, 2008, and provided to the Public Staff, PEC identified a need to add generating capacity to maintain a capacity margin of 11-13%. The capacity margin would be 10.2% in 2011 (excluding 168 MW of undesignated generation in 2010) and 8.6% in 2012 (excluding 297 MW of undesignated generation) absent the addition of the proposed generating capacity. The PEC Resource Plan also includes 370 MW of additional DSM/EE by 2011 and another 117 MW of additional DSM/EE by 2012; if the DSM/EE does not materialize along with the undesignated capacity mentioned above, the capacity margin would be further reduced to 7.6% in 2011 and 5.0% in 2012. Building the 600 MW of combined-cycle generating capacity and achieving 370 MW of DSM/EE by 2011 would put the capacity margin at 14% in 2011.

No one presented any evidence with regard to PEC's forecast, target capacity margin, or need for additional capacity resources in order to meet projected demand in this proceeding. The Commission concludes, based upon the testimony, that PEC requires additional generation capacity in 2011 in order to reliably meet the electricity needs of its customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

This finding is based on PEC's Application filed on April 30, 2008, the testimony of PEC witness Michael Luhrs, and the testimony of Public Staff witnesses Darlene Peedin and Bob Hinton.

PEC witness Luhrs testified that prior to PEC selecting the Richmond County combined-cycle resource to meet its capacity need, PEC solicited and evaluated multiple power purchases. He testified that PEC's evaluation indicated that the combined-cycle self-build, even under very conservative assumptions, was more economical than any of PEC's purchased power opportunities.

Public Staff witnesses Peedin and Hinton testified that they had reviewed PEC's resource selection process, including PEC's evaluation of purchased power opportunities, and found PEC's process to be reasonable.

Witness Peedin testified that the process by which PEC selected the most cost effective intermediate supply for the next increment of generation capacity began with its integrated resource planning process, which is documented by the annual Resource Plans filed by the Company pursuant to Commission Rule R8-61. The Company's 2007 Resource Plan was filed on December 3, 2007, in Docket No. E-100, Sub 114. PEC filed amendments to this plan on March 25, 2008, and April 29, 2008.

Witness Peedin testified that the second part of PEC's process of choosing the next increment of capacity consisted of the issuance of an informal Request for Proposals (RFP) for supply-side generation capacity and evaluation of the bids received in response to that RFP. The evaluation of the bids included a detailed economic analysis to compare the economics of PEC's self-build option to purchased power opportunities. Public Staff witness Peedin testified that PEC solicited proposals from selected participants in the wholesale market in October 2006. This informal RFP required the power suppliers to submit, within a 14-day period, indicative pricing for 250-300 MW of intermediate load delivered into the Company's Eastern Control Area. PEC disseminated its proposal to 15 power suppliers and received responses from three bidders. One of the three bidders did not satisfy PEC's needs for reliable capacity and was eliminated. The other two bidders' proposals were treated as short list proposals, and PEC began working over the following months with the respective bidders to refine their proposals.

According to Ms. Peedin, in evaluating the purchased power opportunities, PEC first used an optimization model called STRATEGIST, which is a planning model that evaluates all resource options and produces the least cost resource plan that will satisfy PEC's reserve margin requirement, given the inputs and assumptions the model considers. Once STRATEGIST comes up with all the possible plans to meet PEC's reserve margin requirement, the resource plans are ranked based on the cumulative present value of revenue requirements (CPVRR).

Second, PEC used PROSYM, which is a production costing model. While this model focuses on many of the same inputs as those included in STRATEGIST, it differs in that it produces a more detailed estimate of production costs resulting from the simulation of the operation of the generating system over time, by optimizing the dispatch of generation resources based on several variables, including load, operational constraints (including generating unit limitations), and incremental costs. Public Staff witness Hinton stated that he reviewed certain inputs incorporated in PEC's production models and found them to be reasonable.

Witness Peedin testified that PEC used STRATEGIST to develop the best possible resource plan for a case including the 600 MW of combined-cycle generation and for alternative cases including the competing purchased power proposals. Essentially, PEC's base case plan, which included the combined-cycle generation, was compared to plans that included each of the competing purchased power proposals. In evaluating each of the proposals against the base case plan, PEC substituted the particular proposal in the place of the proposed new combined-cycle generation to come up with an optimal plan that included the purchase. Once a purchased power proposal was substituted for the combined-cycle facility in the base plan, the optimal plan with the purchase was input into the PROSYM model to capture the impact on system generation production costs, including the impacts from SO_2 and NO_x emissions costs as compared to the base case plan. This process was followed for each purchased power proposal.

All of the information generated by the models was summarized in a financial model spreadsheet developed by PEC. This detailed spreadsheet was essential in comparing the CPVRR of each alternative plan against that of the base case plan. The spreadsheet captured all the details set forth in the purchased power proposals, the changes in the system production costs produced by PROSYM, and other detailed calculations. The detailed proposals included, among other things, fixed and variable costs and start costs. The financial model spreadsheet also captured capacity cost impacts using an economic carrying charge for those resources that were accelerated or deferred due to substituting the purchased power proposal for the proposed new combined-cycle generation. The analysis calculated a deferral/advance credit for each purchased power proposal (including generation and transmission credits) if the purchased power proposal deferred construction of any self-build capacity to a later year. In other words, each purchased power proposal was given a credit for fixed cost savings. PEC also calculated an equity adjustment that was applied to each of the purchased power proposals. The equity adjustment is basically the cost of imputed debt that has been applied to each purchased power proposal to reflect the impact of the future commitment on PEC's capital structure.

Witness Peedin concluded that PEC used reasonable methodologies in evaluating each of the power purchase proposals, as well as conservative assumptions that in essence tended to favor the economics of those proposals over the self-build option. She indicated that PEC worked with each of the bidders to try to enhance the economics of each of the proposals.

Public Staff witness Hinton testified that he evaluated PEC's consideration of the potential impact of the purchased power proposals on PEC's cost of capital. He testified that PEC's evaluation of the purchased power proposals included an equity adjustment. This adjustment recognizes that Standard and Poor's and other credit rating agencies impute a portion of the power purchase costs as debt, which increases the utility's debt leverage. It is believed that the increase in debt leverage could impact the utility's credit-worthiness and raise its cost of capital. This adjustment estimates the additional equity needed to rebalance PEC's balance sheet and capitalization ratios from the purchased power agreement (PPA). Witness Hinton concluded that it was reasonable for PEC to include an equity adjustment to the purchased power proposals. He testified that equity adjustments are not universally applied in the industry and that in Docket No. E-100, Sub 67, the Commission found the information about the effects of PPAs on the cost of capital to be voluminous and conflicting. Mr. Hinton testified that for purposes of this proceeding, the Public Staff believes that it was reasonable for PEC to include an equity adjustment, particularly since excluding the adjustment would not have affected the results of the evaluation.

Witness Hinton also testified that he had studied PEC's projected costs for the natural gas pipeline capacity to serve the proposed combined-cycle unit and the projected commodity costs of natural gas. He also reviewed the projected costs for coal, oil, and emission allowances. In addition, he reviewed the discount rate used in the models and concluded that all of these inputs were reasonable.

Witness Hinton testified that the Public Staff did not have any major concerns with PEC's evaluation of the wholesale market in its resource selection process. However, because PEC conducted an informal process involving select bidders, the Public Staff was not as confident as it would like to have been that PEC completely evaluated the wholesale market to serve its retail customers. In past certificate proceedings, the Public Staff has questioned PEC's method of selecting parties from which to solicit bids, and in Docket No. E-2, Sub 733, the Commission ordered PEC to fully consider the wholesale market for future generation resource additions, whether by formal RFP or other measures that ensure a complete evaluation of the market. More recently, in an order granting certificates to Duke Energy Carolinas, LLC, in Docket No. E-7, Subs 791 and 832, the Commission indicated that an investigation would be instituted to consider whether further guidance should be given as to electric utilities assessing the wholesale market, and such an investigation was recently initiated in Docket No. E-100, Sub 122. Mr. Hinton testified that for purposes of this proceeding, the Public Staff believes that PEC's review of the wholesale market was reasonable.

Based upon this evidence, the Commission finds that PEC evaluated purchased power opportunities and self-build supply side resources in determining that the addition of 600 MW of combined-cycle natural gas fired generation at its Richmond County Energy Complex is the most appropriate resource to meet its resource needs in 2011.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

This finding is based on PEC's Application, the testimony of PEC witness Michael Luhrs, and the testimony of Public Staff witness Bob Hinton.

PEC witness Luhrs testified that PEC's resource plan reflects the projected impact of 771 MW of DSM/EE in 2011 which includes incremental DSM/EE of 370 MW forecasted to be achieved relative to 2008 levels.[1] He also stated that PEC is committed to pursuing renewables. To this end, PEC issued an RFP in which PEC was seeking proposals for the purchase of energy and capacity generated from renewable resources placed in service on or after January 1, 2007. PEC has received responses to its RFP for what appears to be firm renewable generation capacity totaling approximately 400 MW. However, only 37 MW of this 400 MW is potentially available by 2011. Moreover, some proposals rely upon the same renewable resources for fuel, so the total number of proposals that it would be possible to secure is not certain.

Public Staff witness Hinton testified that PEC's peak and energy forecasts are incorporated into PEC's evaluation of supply side alternatives through the Company's STRATEGIST and PROSYM production costing models. He testified that the Public Staff does not have any concerns with regard to the reasonableness of PEC's fifteen-year peak demand and energy forecasts. Witness Hinton testified that PEC incorporated updated forecasts for 2008 that showed little change from the peak demand and energy sales forecasts that were filed in its 2007 Resource Plan. He stated that he had earlier testified in Docket No. E-100, Sub 114 that PEC's peak demand and energy sales forecasts in its 2007 Resource Plan were reasonable.

Witness Hinton then testified that PEC's forecasts included the effects of DSM and EE programs. He stated that the projected MW reductions from existing and new DSM programs are expected to reduce the peak by 771 MW in 2011 and 1,584 MW in 2022. The projected

[1] Incremental DSM/EE achievements through 2017 total 1000 MW as described in PEC's DSM Plan filed separately in conjunction with PEC's 2007 Resource Plan and included in the 2008 Q2 Update.

reductions in energy sales from PEC's new energy efficiency programs are expected to reach 208,929 megawatt hours (MWH) in 2011 and grow to 1,152,586 MWH in 2026. PEC's MWH reductions are the same as identified in the 2007 Resource Plan and the MW reductions are virtually the same.

Public Staff witness Hinton then concluded that PEC could not have reasonably acquired additional DSM or EE resources to offset or delay the need for the proposed new 600 MW of combined-cycle generation. He stated that, given the projected resource needs in 2011, he did not believe that there are additional cost-effective DSM and EE opportunities that would allow PEC to offset or delay the need for additional generation. The projected load reductions from PEC's DSM programs account for over 5% of the peak load in 2011 and over 10% of the peak load by 2022. The projected reductions in energy sales due to PEC's EE programs account for less than 0.5% of its energy sales in 2011 and 1.3% of energy sales by 2022. He testified that, in his opinion, the DSM and EE goals outlined by PEC are reasonable for purposes of this proceeding. He did observe that it is difficult to evaluate the reasonableness of PEC's DSM and EE plans given that PEC has not completed a market potential study, and the Commission has not approved PEC's new programs.

Based upon this evidence, the Commission finds that PEC has included in its resource plan a broad spectrum of DSM and EE programs and measures and renewable generation, and PEC still has a need for additional generation capacity by the summer of 2011 in order to reliably meet the needs of its customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-8

These findings are based upon the forecasts contained in PEC's 2007 Integrated Resource Plan, PEC's Application, the testimony of PEC witness Michael Luhrs, and the testimony of Public Staff witnesses Hinton and Lam.

PEC witness Luhrs testified that his Exhibit 4 is a comparison of the projected load duration curves for 2008 and 2011 for the PEC system. A load duration curve displays the 8,760 hourly load values for a given year in descending order of magnitude against the percent of time that the load values are exceeded. Exhibit 4 shows that the need for intermediate load resources (i.e., resources that operate at capacity factors between 20% and 60%) will increase by approximately 325 MW by 2011.[1] Given this need, PEC's 2007 Resource Plan demonstrates that the type of resource needed by the summer of 2011 is intermediate capacity.

Witness Luhrs then referred to PEC's 2007 Resource Plan, which demonstrates that gas fired generators are the most environmentally benign, economical, large-scale capacity additions available for meeting peaking and intermediate loads. New designs of these technologies are more efficient (as measured by heat rate) than previous designs, resulting in a smaller impact on the environment. The advancements associated with combined-cycle operation and design enable a greater operational flexibility relative to combustion turbines without heat recovery

[1] The load duration curves in Exhibit 4 are net of energy efficiency programs. Also, the load data for 2011 does not include 100 MW of wholesale load in PEC's control area that PEC currently serves and expects to serve going forward.

steam generators and steam turbines. This is due to several factors: each combustion turbine can be operated in a simple-cycle mode or in concert with its heat recovery steam generator and the steam turbine to enhance reliability and optimize unit operations; the combined-cycle unit will contain approximately 70 MW of duct firing capability that can be dispatched during peak demand periods, much the same way as a peaker, but at a fraction of the cost of installing an additional combustion turbine; and a combined-cycle unit can be economically utilized across a wide capacity range, approximately 20% to 60%, which means it can grow with system energy needs unlike oil fired combustion turbines which are logistically and environmentally hindered from capacity factors greater than roughly five to ten percent.

Witness Luhrs testified that the proposed facility will consist of two combustion turbines each with a heat recovery steam generator to produce steam to drive a single steam turbine. The two combustion turbines will be primarily fueled by natural gas; however, they will be capable of running on ultra low sulfur fuel oil if natural gas is not available. The facility will have bypass dampers installed to ensure that the plant can be operated in simple-cycle or combined-cycle mode to enhance reliability and operational flexibility. Installing the combined-cycle unit at the Richmond County site, which was originally designed to be able to accommodate four combined-cycle units, will optimize use of the existing infrastructure including the land, gas transportation pipeline, water supply and existing plant auxiliary systems, thus making more efficient use of plant facilities and personnel.

In addition, witness Luhrs testified that the combined-cycle facility fueled by natural gas is the cleanest and most efficient fossil fuel generation currently available. There are virtually no sulfur dioxide (SO_2) emissions, and nitrogen oxide (NO_x) emissions are approximately 80 percent less than modern coal-fired generation. Further, the gas-fired combined-cycle facility will help PEC adapt to and comply with any carbon legislation because its emissions of carbon dioxide are approximately 60% less than new coal-fired generation of equivalent capacity.

Finally, PEC witness Luhrs stated that combined-cycle generating capacity is the least cost source of reliable intermediate capacity available. Since 1990, PEC has placed in service approximately 2,030 MW of new combustion turbines (many of which rely on oil as a fuel source) and 460 MW of combined-cycle capacity. Combined-cycle capacity helps minimize the usage of higher cost oil-fired combustion turbines. PEC has extensive experience in both negotiating the purchase of these facilities as well as their installation and construction. The cost to PEC, even under very conservative assumptions, to acquire this new capacity will be less than the cost to acquire such capacity from another source. The equipment and the engineering, procurement, and construction work will be procured in accordance with PEC guidelines for procurement which provide for both technical and commercial evaluations of bids. PEC will invite proposals from different equipment vendors for the purchases of the combustion turbine generators and other items of major equipment. PEC has already purchased the steam turbine generator on the secondary market at a considerable savings. PEC will also request bids from available and qualified engineering and construction firms to construct the facility. Therefore, witness Luhrs stated the combined-cycle facility will be the result of a request for proposals. An update to the projected cost of the facility is confidential and was included as an exhibit attached to witness Luhrs' testimony. No specific issue was raised as to the validity of PEC's cost estimates.

Public Staff witness Lam agreed with PEC that combined-cycle generation is the best resource to meet PEC's capacity needs. He testified that a combined-cycle facility is the best choice to produce the additional capacity and energy required to maintain the appropriate capacity margin. He confirmed that a comparison of PEC's projected load duration curves for 2008 and 2011 shows an increase in the need for intermediate capacity of approximately 325 MW, and the selection of a combined-cycle unit fulfills this need in a cost effective manner.

Witness Lam testified that the only other type of power plant that could supply the needed energy in the time frame required would be a combustion turbine (CT). While a CT is less costly to construct, it has higher operating costs than a combined-cycle unit because a CT is inherently less efficient. Due to lower capital costs, a CT has a slightly lower total per-unit cost than a combined-cycle unit when operated at capacity factors below 10%; however, if actually required to operate at a capacity factor greater than 10%, a CT would then become an economic liability because it uses significantly greater quantities of natural gas to generate the same quantity of energy as a combined-cycle unit. A combined-cycle unit typically runs at a capacity factor of over 15% and needs to average running at a capacity factor closer to 30% to supply the quantities of additional energy identified in the PEC Resource Plan. The greater the capacity factor over 10% at which a CT is required to run, the greater the economic risk due to the quantity and cost of natural gas needed to run the CT, and the relative inefficiency of operation as compared to a combined-cycle unit. This disadvantage of a CT versus a combined-cycle unit is magnified further if both types of units were to have to run using backup fuel oil, which would make the per unit cost (¢/kWh) of both types of units over twice that of the primary fuel, which is natural gas. This particular combined-cycle unit also has the advantage of being able to run as two simple cycle CTs in the event that peaking capacity is required instead of intermediate capacity.

Witness Lam concluded that given the energy and capacity needs identified in PEC's 2007 Resource Plan and included in Company witness Luhrs' testimony, the choice of any other power plant would not be in the best interests of PEC's North Carolina retail ratepayers. Witness Lam also concluded that the construction of this 600 MW combined-cycle unit will enable PEC, if it chooses, to reduce its system pollution by substituting the cleaner and more efficient combined-cycle generation for some of PEC's less efficient and dirtier coal-fired intermediate generation. In summary, he concluded that the proposed unit will supply the required capacity and energy at a reasonable estimated total cost for the referenced time frame.

With regard to the choice of the existing Richmond County Energy Complex for the location of the new combined-cycle facility, PEC witness Luhrs testified that there are six key factors that are considered in selecting a site for a natural gas fired generation facility. They are: (1) locate on or near a natural gas pipeline with sufficient existing or planned capacity to support the proposed generation addition; (2) locate on or near electrical transmission facilities with a voltage of 230 kV and above having sufficient capacity or expansion capability to receive the additional generation; (3) locate in an area with relatively low impact on the surrounding community; (4) locate in a county that has Environmental Protection Agency (EPA) attainment status for applicable pollutants; (5) locate in a county that is at least 100 kilometers from the nearest EPA Class I area; and (6) locate near an adequate source of water.

PEC witness Luhrs testified that the Richmond Site is located on PEC property at an existing PEC plant and satisfies all six criteria better than any other site, primarily due to the fact that the site was originally designed with a layout to accommodate four combined-cycle units and has significant existing infrastructure that can be utilized to achieve economies of scale. The Richmond County site is adjacent to a major 500 kV/230 kV transmission substation with expansion capability. A major Piedmont Natural Gas Company pipeline serves the site and has excess capacity that requires only minor upgrades to serve these units. The site has a railroad siding and the area is sparsely populated. In addition, the current zoning designation allows for utility power generation and substations as permitted uses. The site has adequate county water supply, and PEC has previously made arrangements with Richmond County to utilize the necessary water. The Richmond site is well-buffered from adjacent highways, and the county has EPA attainment status. Importantly, the site is approximately 200 kilometers from the nearest EPA Class I area. Also, the site already has significant staff and facilities to support the capacity addition. Finally, the proposed combined-cycle facility is supported by local governmental and economic development leaders.

Witness Luhrs testified that this plant will require some transmission line upgrades, but fifty percent of these upgrades are required to accommodate load growth and maintain system reliability regardless of whether additional generation is built at the Richmond site. Building the transmission required for the plant at the same time as the required system upgrades will benefit the overall economics and minimize the timeline of potential disruption due to construction activities.

Public Staff witness Lam agreed that the Richmond Site is the best location for this new generation. He testified that the existing Richmond County Energy Complex location is an excellent choice to build the new 600 MW combined-cycle generation. Because this is an existing power station, and thus a brownfield site, it has much of the infrastructure that a combined-cycle plant requires, such as an existing transmission network and a transmission switching station, a gas pipeline of sufficient capacity, rail unloading facilities, cooling water availability, and other station requirements. There is also sufficient land at the site to accommodate the construction of this additional unit. Consequently, the use of the existing Richmond County Energy Complex brownfield site should result in a lower cost of building this unit as compared to a greenfield site.

Witness Lam recommended that the Commission issue a certificate to PEC to construct the proposed combined-cycle unit at the existing Richmond County Energy Complex. He stated that constructing the proposed generation facility at the Richmond Site is the most energy efficient, economical, and dependable method of meeting PEC's demand and energy requirements in the near term and into the future while remaining within today's government mandated environmental parameters.

Based upon this evidence, the Commission finds that the addition of 600 MW of combined-cycle natural gas-fired generation at PEC's Richmond County Energy Complex by the summer of 2011 is the most cost effective and appropriate resource to meet PEC's customers' forecasted electricity needs and that a certificate of public convenience and necessity should be issued. The Commission finds and concludes that the cost estimates are reasonable and, pursuant to G.S. 62-110.1(e), said estimated construction costs are approved.

IT IS, THEREFORE, ORDERED as follows:

1. That PEC's application for a certificate of public convenience and necessity to construct approximately 600 MW of combined-cycle generation capacity at PEC's Richmond County Energy Complex in North Carolina is hereby approved. This order shall constitute the certificate.

2. That PEC shall file with the Commission in this docket a progress report and any revisions in the cost estimates for this 600 MW combined-cycle addition to the Richmond County Energy Complex on an annual basis, with the first such report due no later than one year from the date of this order.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of October, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

jc101308.01

DOCKET NO. E-7, SUB 791
DOCKET NO. E-7, SUB 832

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for	)	
Approval for an Electric Generation Certificate of	)	
Public Convenience and Necessity to Construct	)	
620 MW Buck Combined Cycle Project	)	
	)	
and	)	ORDER ISSUING CERTIFICATES
	)	OF PUBLIC CONVENIENCE AND
In the Matter of	)	NECESSITY
Application of Duke Energy Carolinas, LLC for	)	
Approval for an Electric Generation Certificate of	)	
Public Convenience and Necessity to Construct	)	
620 MW Dan River Combined Cycle Project	)	

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on March 11, 2008; Eden City Hall, 308 E. Stadium Drive, Eden, North Carolina, on February 27, 2008; and Salisbury City Hall, 217 South Main Street, Salisbury, North Carolina, on February 28, 2008.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Robert V. Owens, Jr.; Lorinzo L. Joyner; James Y. Kerr, II; Howard N. Lee; and William T. Culpepper, III

APPEARANCES:

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For the Using and Consuming Public:

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For the Electric Power Supply Association:

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BY THE COMMISSION: On May 11, 2005, Duke Power, a division of Duke Energy Corporation, now Duke Energy Carolinas, LLC (Duke or the Company) filed in Docket No. E-7, Sub 791, preliminary information with the North Carolina Utilities Commission (Commission) pursuant to Commission Rule R8-61(a) regarding a Certificate of Public Convenience and Necessity (CPCN) to construct a new 600 MW combined cycle natural gas-fired electric generation facility and related transmission facilities to be located at its existing Buck Steam Station site in Rowan County.

On June 29, 2007, Duke filed in Docket No. E-7, Sub 791, updated preliminary information regarding construction of a nominal 600 to 800 MW combined cycle natural gas-fired electric generation facility and related transmission facilities to be located at its existing Buck Steam Station site in Rowan County (the Buck Combined Cycle Project) and filed in Docket No. E-7, Sub 832, preliminary information regarding construction of a nominal 600 to 800 MW combined cycle natural gas-fired electric generation facility and related transmission facilities to be located at its existing Dan River Steam Station site in Rockingham County (the Dan River Combined Cycle Project).

On December 14, 2007, Duke filed two applications pursuant to G.S. 62-110.1 and Commission Rule R8-61(b) for CPCNs for the 620 MW Buck and Dan River Combined Cycle Projects (the Projects), along with the pre-filed direct testimony and exhibits of Ellen T. Ruff, President; Janice D. Hager, Managing Director of Integrated Resource Planning and Environmental Strategy, Duke Energy Corporation; and Mark Landseidel, General Manager -- Projects for Duke Energy Corporation. The Company also filed a motion to consolidate the two CPCN applications for hearing and disposition.

On January 23, 2008, the Commission issued an order consolidating the applications, scheduling hearings, establishing procedural deadlines, and requiring public notice. The intervention of the Attorney General was recognized pursuant to G.S. 62-20, and the intervention of the Public Staff was recognized pursuant to G.S. 62-15(d). Petitions to intervene were filed by, and allowed for, Carolina Utility Customers Association Inc. (CUCA); Carolina Industrial Group for Fair Utility Rates (CIGFUR); LS Power Associates, L.P. (LS Power); the Electric Power Supply Association (EPSA); and Aloca, Inc. and Alcoa Power Generating Inc.

LS Power filed the direct testimony of Lawrence J. Willick, on February 27, 2008. The Public Staff filed the testimony and exhibits of John R. Hinton, Thomas S. Lam, and Michael C. Maness on February 27, 2008.

A public hearing was held in Eden on February 27, 2008. The following public witnesses testified at the Eden hearing: Al Smith, Cindy Adams, and Wayne Tuggle. A public hearing was held in Salisbury on February 28, 2008. The following public witnesses testified at the Salisbury public hearing: Randy Welch, Bill Wagoner, Ann Brownlee, T. Jefferson Morris, and Bob Wright.

On March 6, Duke filed the rebuttal testimony and exhibits of Christopher M. Fallon, Managing Director of Strategy and Business Planning for Duke Energy Corporation, and witness Hager.

The case came on for hearing as scheduled on March 11, 2008, and the pre-filed testimony was received subject to cross-examination. Following the hearing, Duke filed two late-filed exhibits as requested by the Commission, and the parties filed proposed orders and/or briefs.

Based upon consideration of the testimony and exhibits presented herein and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke is a public utility providing electric utility service to customers in its franchised service area in North Carolina subject to the jurisdiction of the Commission.

2. Duke filed applications for CPCNs for the Buck and Dan River Combined Cycle Projects on December 14, 2007. The Commission has jurisdiction over the applications pursuant to G.S. 62-110.1, which provides that a public utility must obtain a CPCN from the Commission prior to constructing electric generating facilities to be directly or indirectly used for public utility service.

3. Duke plans to construct a nominal 620 MW combined cycle natural gas-fired electric generating unit and related transmission facilities at its existing Buck Steam Station site in Rowan County and to construct similar facilities at its Dan River Steam Station site in Rockingham County. As part of the addition of the Buck Combined Cycle Project, Duke plans to retire the existing Buck coal-fired Units 3 and 4 (totaling 113 MW), which began operation in 1941 and 1942, respectively. As part of the Dan River Combined Cycle Project, the Company plans to retire the existing Dan River coal-fired Units 1 and 2 (totaling 134 MW), which began operation in 1949 and 1950, respectively. The Company plans for the Buck Combined Cycle Project to begin commercial operation in simple cycle mode during the summer of 2010 and to begin commercial operation in combined cycle mode by the summer of 2011. The Company plans for the Dan River Combined Cycle Project to begin commercial operation in simple cycle mode during the summer of 2011 and to begin commercial operation in combined cycle mode by the summer of 2012.

4. Duke's 2007 Annual Plan[1] shows substantial load growth and the need for significant capacity additions over the next twenty years. The 2007 Annual Plan shows a cumulative need for resource additions of 990 MW by 2010, 2,340 MW by 2011, and 3,190 MW by 2012.

5. The Company's 2007 Annual Plan included 500 MW of undesignated wholesale load at the time it was filed in 2007; the Company has since executed wholesale contracts totaling approximately 200 MW. The 2007 Annual Plan also reflects the retirement of

[1] The load forecast portion of Duke's 2007 Annual Plan has been scheduled for hearing beginning July 1, 2008, by order of April 17, 2008, in Docket No. E-100, Sub 114. That order was issued after the hearing in the current dockets and after submission of the briefs and proposed orders herein. The present order in these dockets is without prejudice to the rights of the parties in the Sub 114 proceedings.

approximately 1,000 MW of older, less-efficient coal-fired units as part of the Company's commitments related to recent approval of Cliffside Unit 6.

6. In the 2007 Annual Plan, Duke tested its resource portfolio options against a wide range of sensitivities and scenarios. Duke concluded that the portfolios with combined cycle units in the 2010 to 2012 time frame were the best options. The choice of combined cycle facilities for the Company's next increment of generation capacity is consistent with the Company's 2007 Annual Plan.

7. Duke conducted technical and economic evaluations of alternative supply side resource options. The combined cycle technology proposed by Duke is the appropriate technological option, and the proposed phased-in approach is an appropriate way to provide additional intermediate generation capacity by 2010-12.

8. Duke considered a broad spectrum of demand-side options, energy efficiency programs, and renewable resources in its integrated resource planning process and in making the decision to pursue the Buck and Dan River Combined Cycle Projects as proposed. Duke cannot rely upon demand-side management, energy efficiency, and renewables to eliminate or delay its needs for additional intermediate generating capacity in the 2010-2012 time frame.

9. Duke evaluated the wholesale market by issuing a Request for Proposals (RFP) in May 2007. The RFP sought conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 time frame and up to 2000 additional MW beginning in the 2013 time frame. The RFP allowed bids for purchase power agreements or for the purchase of existing or new generation assets, it was open to bidders in the wholesale marketplace and self-build options, and it specified that the northern region of Duke's service territory was preferred for new resource additions.

10. Duke retained Burns & McDonnell Corporation as an independent, third-party facilitator. Burns & McDonnell issued the May 2007 RFP, answered bidder questions, received and reviewed all bids, and submitted redacted copies of the bids without names and locations for evaluation by Duke. Duke evaluated the redacted bids and developed a short list. At that point, Duke asked for release of the bidders' names.

11. Duke requested all short-listed bidders to "refresh" their bids in order to provide updated bids based on more recent information and to gain greater clarity from the bidders. Duke chose 15 years as the maximum term for PPA bids and asked bidders offering PPAs to provide refreshed bids with terms of 15 years or less. Duke concluded from its evaluation of the refreshed bids that the Buck and Dan River Combined Cycle Projects were the lowest cost combined cycle bids that addressed the concerns in its northern region.

12. The new generating units of the Buck and Dan River Combined Cycle Projects will be the first combined cycle units on the Duke system and will provide operational flexibility, fuel diversity, system benefits, and reliability. Both the Buck and Dan River Combined Cycle Projects will provide needed transmission voltage stability support for the Company's northern region and will add fuel diversity to Duke's generation portfolio. The Buck and Dan River

Combined Cycle Projects are reasonable and appropriate options to serve the Company's growing customer needs and to replace the intermediate load coal plants that will be retired as part of Duke's fleet modernization plans.

13. Duke will use of state-of-the-art emission control technology in the Buck and Dan River Combined Cycle Projects. The use of cooling towers in the design of the Projects will minimize impacts to the Yadkin and Dan Rivers. The necessary environmental permitting is subject to the jurisdiction of other State agencies.

14. Duke conducted a comprehensive siting process before selecting the Buck and Dan River sites. Issues of historical preservation relating to the sites must be addressed and decided by the appropriate State and federal agencies.

15. The Company's estimated construction costs for the Buck and Dan River Combined Cycle Projects are reasonable and approved. Duke shall submit a progress report each year during construction that includes any revisions in the cost estimates as required by G.S. 62-110.1(f).

16. The issuance of CPCNs for the Buck and Dan River Combined Cycle Projects, including related transmission facilities, is required by the public convenience and necessity. The Projects are key components of Duke's fleet modernization plan, and the CPCNs granted herein are conditioned upon the retirement of Buck coal-fired Units 3 and 4 and Dan River coal-fired Units 1 and 2, upon commercial operation of the Buck and Dan River combined cycle units. The CPCNs granted herein are also conditioned upon the Company's continuing to pursue negotiation of appropriate long-term, firm natural gas transportation arrangements for the Projects.

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

The evidence in support of these findings of fact is found in the CPCN applications for the Buck and Dan River Combined Cycle Projects, the testimony and exhibits in this docket, and the statutes and case law concerning the jurisdiction of the Commission. These findings are informational, procedural, and jurisdictional in nature.

G.S. 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. State ex rel. Utilities Comm. v. Empire Power Co., 112 N.C. App. 265, 278 (1993), disc. rev. denied, 335 N.C. 564 (1994); State ex rel. Utilities Comm. v. High Rock Lake Ass'n, 37 N.C. App. 138, 141, disc. rev. denied, 295 N.C. 646 (1978). A public need for a proposed generating facility must be established before a certificate is issued. Empire, 112 N.C. App. at 279-80; High Rock Lake, 37 N.C. App. at 140.

Beyond need, the Commission must also determine if the public convenience and necessity are best served by the generation option being proposed. The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. State ex rel. Utilities Comm. v. Casey, 245 N.C. 297, 302 (1957). "[Chapter 780 of the 1975 Session Laws], codified as G.S. 62-110.1(c)-(f), directs the Utilities Commission to consider the present and future needs for power in the area, the extent, size, mix and location of the utility's plants, arrangements for pooling or purchasing power, and the construction costs of the project before granting a certificate of public convenience and necessity for a new facility." High Rock Lake, 37 N.C. App. at 140-1. As hereinafter discussed, the Commission has considered all of these factors in determining whether the public convenience and necessity are served by Duke's proposals in these dockets.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence in support of this finding of fact is found in the verified applications and the testimony and exhibits of Duke witnesses Mark Landseidel and Janice Hager. This finding summarizes the Company's plans for the additions and retirements related to the Buck and Dan River Combined Cycle Projects, hereinafter discussed more fully.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-5

The evidence in support of these findings of fact is found in the 2007 Duke Annual Plan and in the testimony and exhibits of Duke witnesses Ruff and Hager and Public Staff witnesses Hinton and Lam. These findings relate to the need for additional generating capacity.

Duke witness Ruff testified that, over the past five years, Duke has added approximately 50,000 new customer accounts each year, with each account typically representing a greater number of actual users of electricity at each location. She testified that a reliable supply of electricity is essential to creating an environment that will support the State's growth and that the Buck and Dan River Combined Cycle Projects are essential to ensuring that low cost and reliable energy continues to be available to meet growing demand.

Duke witness Hager testified concerning the Integrated Resource Planning (IRP) process that led to the development of the 2007 Duke Annual Plan and the decision to add the Buck and Dan River Combined Cycle Projects. Witness Hager testified that the Company develops and files an annual resource plan based upon a 20-year load forecast and a target planning reserve margin of 17%. The Buck and Dan River Combined Cycle Projects are just two components of the plan resulting from the 2007 planning process. Ms. Hager explained that the Company's current load forecast reflects a 1.6% average annual growth rate in summer peak demand and a 1.4% average annual growth rate in winter peak demand and total energy usage. As a result, Duke expects to face an average annual growth rate of approximately 350 MWs per year of energy.

Witness Hager testified that prudent planning requires a plan that is robust under many scenarios and that contains a number of options in order to respond to uncertainties such as the prospects for the enactment of federal greenhouse gas emission legislation, the adoption of new renewable energy portfolio standards, the acceptance and effectiveness of new demand side management (DSM) and energy efficiency (EE) programs, the revival of nuclear generation, and increases in the worldwide demand for building materials and equipment. The Company's 2007 planning process considered two scenarios: a Reference Case without CO_2 regulation (the

Reference Case) and a Carbon Case with CO_2 regulation and a renewable portfolio standard (the Carbon Case). Ms. Hager testified that the Company's resource planning approach includes consideration of both quantitative analysis and qualitative considerations. The quantitative analyses suggested that a combination of additional baseload, intermediate, and peaking generation; renewable resources; EE; and DSM is required over the next twenty years to meet customer demand reliably and cost-effectively. Under the Reference Case, a portfolio consisting of 3,100 MW of new natural gas combined cycle capacity; 4,052 MW of new natural gas combustion turbine capacity; 1,117 MW of new nuclear capacity; 1,016 MW of DSM; and 790 MW of EE was selected. Under the Carbon Case, a portfolio consisting of 1,240 MW of new natural gas combined cycle capacity; 3,560 MW of new natural gas combustion turbine capacity; 1,117 MW of new nuclear capacity; 1,016 MW of DSM; 790 MW of EE; and 1,135 MW of renewable resources was selected.

The 2007 Duke Annual Plan identified a cumulative resource need for 990 MW of capacity in 2010, which grows to 2,340 MW by 2011 and to 3,190 MW by 2012. Witness Hager testified that the need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, demand side reductions, and expirations of purchase power contracts. The Company plans to retire approximately 1,000 MW of older coal capacity as part of the Commission's approval of the addition of Cliffside Unit 6 and to retire approximately 500 MW of older natural gas and fuel oil combustion turbine capacity during the planning period.

Public Staff witness Hinton evaluated Duke's 2007 forecast of peak demand and energy sales, and he testified that the peak demand and energy sales forecasts were reasonable and that the forecasted growth rates are comparable to those contained in previously approved Annual Plans. Witness Hinton stated that his review of the Annual Plans involves evaluating the last ten years of annual peaks and weather-normalized peaks. Public Staff witness Lam testified that the need for the Buck and Dan River Combined Cycle Projects is adequately supported since the most recent Annual Plan shows a need for almost 1,000 MWs of capacity and over 4,300,000 MWhs of energy above the 2008 level in the year 2011 and a need for almost 2,000 MW of capacity and almost 6,000,000 MWhs of energy in the year 2012 as compared to the year 2008.

Based on the evidence presented in this proceeding, the Commission concludes that Duke has demonstrated a need for the addition of generation capacity in the 2010-12 time frame to serve its customers' needs. In doing so, the Commission notes that the March 21, 2007 Order Granting Certificate of Public Convenience and Necessity with Conditions in Docket No. E-7, Sub 790 (the Cliffside Unit 6 CPCN) stated that, as a consequence of the decision to approve only one of the two units requested by the Company in that docket, "construction of intermediate gas-fired combined cycle capacity could be moved up" to make up the difference in capacity needs and to regain the desired reserve margin.

A sub-issue relating to the question of the need for additional generating capacity concerns the inclusion of 500 MW of unspecified wholesale load in Duke's resource planning. Witness Hager testified that the 2007 Annual Plan included 500 MW of undesignated wholesale load at the time it was filed on November 15, 2007, but that the Company has since executed wholesale contracts to serve two electric membership corporations in North Carolina totaling approximately 200 MW. Witness Hager emphasized that the Buck and Dan River Combined Cycle Projects are needed regardless of whether Duke ultimately signs contracts to serve and actually serves the remaining 300 MW of undesignated wholesale load included in its 2007 Annual Plan. She testified that the 500 MW of undesignated wholesale load in the 2007 Annual Plan is small in relation to a total system demand approaching 20,000 MW and that this amount of capacity is within the margin of long-term load forecasting error and also well within the capability for mid-range adjustments of supply side resources. Witness Hager testified that the 2007 Annual Plan also includes a new 632 MW combustion turbine facility addition in 2011, for which the Company has not yet sought a CPCN, that could be deferred or not built if load does not materialize. Duke maintained that such a level of undesignated wholesale load poses virtually no risk to retail ratepayers.

Public Staff witnesses Hinton and Lam testified that the Company's use of undesignated load of 500 MW in the Annual Plan, now reduced to 300 MW after execution of two contracts, was reasonable for purposes of this proceeding. The Public Staff panel was asked how the Commission can assure itself that there are not two or more utilities planning for the same undesignated load and whether there are risks to captive ratepayers from the construction of generation resources to meet such forecasted wholesale sales obligations. Public Staff witness Hinton responded that, if two utilities were planning to meet the same load, the issue would be investigated in the review of the companies' Annual Plans and in future CPCN proceedings. Witness Maness cited the Duke merger conditions in support of his contention that Duke bears the risk of any undue losses as a result of taking on wholesale load.

The Commission notes that Duke has traditionally planned for expected growth in wholesale load in the same way that it has planned for forecasted growth in its retail load, and the Commission concludes that inclusion of some level of unspecified wholesale load growth in the Company's 2007 Annual Plan is reasonable. The specific level of 500 MW of unspecified wholesale commitments included in the 2007 Annual Plan seems reasonable, especially since 200 MW is no longer unspecified. The Commission concludes that such a level of undesignated wholesale load poses little risk to retail ratepayers, especially in light of the opportunities for further Commission review and the regulatory conditions by which utilities assume the risk of stranded costs resulting from wholesale market activity. In any event, the Commission concludes that there is a need for the Projects apart from this 500 MW (now 300 MW) of undesignated wholesale load.

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

The evidence in support of these findings of fact is found in the 2007 Duke Annual Plan and in the testimony and exhibits of Duke witnesses Ruff, Hager, and Lanseidel; Public Staff witnesses Maness and Lam; and LS Power witness Willick. These findings of fact relate to the Company's evaluation of the available and feasible generating technologies and the Company's selection of combined cycle technology with a phased-in approach.

Witness Hager testified that the 2007 planning process revealed the need for additional gas-fired generation in the 2010-2012 time frame. The resource options available to meet the need during that time frame include coal-fired resources, natural gas-fired resources, renewable resources, DSM, and EE. Nuclear generation is not an option because of the long construction lead times associated with nuclear facilities. Additional new coal-fired generation is not an option during the relevant time frame given the absence of evidence of need for additional baseload capacity in the relevant period as discussed in the Commission's Order in Docket No. E-7, Sub 790. Although the 2007 Annual Plan also includes renewables, DSM, and EE, such resources are not viable options for meeting the 2010-2012 capacity needs at issue in these dockets, as discussed elsewhere herein. The only viable options for meeting the anticipated needs during the relevant period are simple cycle combustion turbines (CTs) and combined cycle combustion turbines (CCs).

Witness Hager testified that Duke's quantitative analysis indicated that CTs almost always involve a slightly lower cost for customers than CCs during the 2010-2012 time frame. However, testing portfolios with CCs substituted for CTs during that time frame found very little difference in the impact of the alternative portfolios on customers -- less than a 0.5% difference in the present value of revenue requirements (PVRR) over the planning horizon. Witness Hager testified that the difference in PVRR costs for CCs earlier instead of CTs ranged from $60 million to $300 million; however, the magnitude of this range should be evaluated over a 35-year period and compared to a total PVRR of $60 or $70 billion. From the Company's standpoint, this slight difference in PVRR between the CC and CT portfolios made the two resource options "essentially equivalent."

The Company presented testimony that the benefits of the Buck and Dan River Combined Cycle Projects, versus CTs, outweigh their slightly higher PVRR. First, Duke currently has no CCs in its generation portfolio, but already has 3,000 MW of CTs. The addition of the combined cycle projects will add diversity to the Company's resource mix. Second, CCs are much more efficient than CTs, with much better heat rates. Third, CC units can operate at a wider capacity factor range, operating 10-60% of the time versus less than 20% for CTs. Fourth, under the scenarios involving simple cycle CTs in the 2010-2012 time frame, in lieu of CCs, the simple cycle CT portfolio sometimes has a capacity factor as high as 15%, which is higher than the preferred capacity factor for CTs. Witness Hager testified that utilizing CTs at such a high capacity factor was unacceptable. Company witness Mark Landseidel, an engineer who has responsibility for the development and construction of gas-fired new generation projects for Duke, testified that he couldn't understand why anyone would want to design a CT plant to operate at higher capacity factors than those associated with the operation of a peaking facility. Witness Hager also testified to the relative dispatch cost by unit type and to the dispatch-cost advantage of CCs over even relatively new CTs.

In addition, witness Hager testified that CCs provide a significant customer benefit and hedge against extreme weather and higher than normal outages. CTs, instead of CCs, would expose customers to the risk of high fuel costs. Witness Hager summarized the case in support of Duke's decision to add CCs instead of CTs by testifying that "what we concluded is that it would be in the best interest of our customers, even if the economics would say under specific circumstances it might not be the absolute lowest cost. It's in the best interest of our customers to move forward with CCs."

Witness Ruff testified to the Company's plans to retire approximately 1,000 MW of older, less-efficient coal units as part of the approval of Cliffside Unit 6. The Company's older coal retirements were originally tied to MW-per-MW savings from new EE programs, but the Company agreed to a fixed MW schedule for the retirements, without regard to achieving EE savings, as part of the Cliffside 6 air permit conditions. Witness Ruff testified that Duke is committed to reducing its carbon footprint and that the Buck and Dan River Combined Cycle Projects will emit approximately 70% less CO_2 per kWh of electricity generated compared to the coal-fired units that will be retired at the sites.

Witness Hager testified that the Buck and Dan River Combined Cycle Projects are the best replacements for the coal units that will be retired. The Company will retire approximately 1,000 MWs of coal-fired generation, but this generation must be replaced with new resources in order to meet existing and future load growth. The units that will be retired are the least efficient coal units in the Duke fleet. The Buck and Dan River Combined Cycle Projects will operate as intermediate resources and will provide efficient, low-emission alternatives to these retired coal units.

Duke witness Landseidel testified that the Buck and Dan River Combined Cycle Projects will each consist of nominal 620 MW natural gas-fired CC generating plants and related transmission facilities. He discussed the Company's technology evaluation and the selection of the "2X1F" technology as providing the best operational flexibility for the Company (including daily starts, minimum load capability, and minimum starting times). The Company concluded that this technology is proven, commercially available, cost effective, flexible, and highly efficient and that it will best meet the Company's intermediate load generation needs. Witness Landseidel also testified to the natural gas pipeline facilities that will be added as part of the Projects and to the long-term natural gas transportation agreements that Duke Energy is negotiating for the Projects.

Public Staff witness Maness testified that the quantitative analysis component of the Company's Annual Plan consisted of several discrete steps designed to create the most cost-effective schedule for installing generation capacity over the planning horizon (in this case, 20 years). He stated that the schedule developed as a result of this analysis is not intended to be written in stone; instead, it is subject to change as the planning process is repeated on an annual basis. However, with regard to near-term generation capacity installation decisions, quantitative analysis plays an important role in making the final decision.

Mr. Maness testified that the quantitative analysis began with the identification and initial screening of generation technologies to determine which were technically feasible and commercially available and could be installed and operated within reasonable cost parameters. After initial screening, several of the most attractive technologies were passed to a stage of the analysis in which they were included as possible installation choices in a long-range simulation model (referred to in the past as the Capacity Expansion Module, or CEM) that is designed to determine the most cost-effective plans for generation expansion. The CEM results were then used to construct several portfolios that the Company felt were representative of the most cost-effective installation plans determined using the CEM, except that the new units now all consisted of feasible increments of each type of potential capacity; these portfolios were then compared to each other, in a process referred to by Duke as portfolio analysis, on a revenue requirements basis in base cases and over several sensitivities. The portfolios were then ranked against each other in terms of comparative revenue requirements over a long-term period

Mr. Maness testified that all of the Company's CEM analyses showed gas-fired generation to be the most cost-effective capacity to install in the 2010-2016 time frame. As a result of the CEM runs, the Company constructed portfolios for testing in the portfolio analysis that reflected two basic patterns of CC installation over the 2010-2020 time frame: some with CCs added in the 2011-2012 period and some with CCs delayed generally until the 2014-2016 period (one portfolio delayed CC installation until 2020). The results of the portfolio analysis generally showed that the portfolios delaying CC installation in favor of earlier CT installation were lower cost in terms of the PVRR, but only by amounts ranging from approximately 0.1%-0.5% of the average revenue requirements of all portfolios tested. However, notwithstanding the results of the quantitative analysis, which generally favored a delay in CC installation, the Company made a determination that it was reasonable and appropriate to plan on earlier CC additions for reasons of fuel diversity, flexibility, and unit reliability. Mr. Maness testified that, overall, it appears that the quantitative analysis portion of the 2007 Annual Plan was conducted in a reasonable manner. In summary, Mr. Maness testified that, based on his review and the testimony of Public Staff witness Lam, the overall results of the quantitative analysis do not invalidate the choice of combined cycle generation as Duke's next increments of installed capacity

Public Staff witness Lam testified that the choice of any generation technology other than CCs would not be in the best interests of Duke's retail ratepayers. Witness Lam testified that the only alternative to CCs in the relevant time frame would be CTs, which would cost less to construct but more to operate because of their relative inefficiency. Witness Lam testified that even though CTs have a slightly lower per-unit cost when operated at capacity factors below 10%, CTs would be an economic liability if required to run at capacity factors over 10% due to the greater economic risk resulting from changes in the cost of natural gas, the relative inefficiency of CT operation compared to CCs, and unexpected weather and operational difficulties. Witness Lam testified that Duke's generation system already has the right amount of peaking (or CT) resources, but needs more intermediate generation. Witness Lam also testified to the benefits that the addition of the Buck and Dan River Combined Cycle Projects would provide by enabling the Company to replace older, less efficient coal-fired units.

LS Power witness Willick testified that the Commission should deny CPCNs for reasons discussed hereinafter, or, in the alternate, should approve only the construction of CT units since they would be the lower cost option.

In determining whether it is appropriate to issue a CPCN, the Commission must determine whether the public convenience and necessity are best served by the generation option chosen by the utility. The Commission determines that it was appropriate for Duke to conduct the long-range quantitative modeling analysis of various supply-side options and that the Commission must take from these analyses the information that is helpful in making the present decision. As stated in the March 21, 2007 Order Granting Certificate of Public Convenience and Necessity with Conditions in Docket No. E-7, Sub 790, "it is appropriate for the Commission to consider many factors in making this decision, including the overall integrated resource plan of the utility, but the Commission is not bound by the results of any single least-cost computer study." In this case, the Commission finds and concludes that gas-fired CC facilities will provide substantial benefits in meeting Duke's growing needs and are the best resource options for the 2010-2012 time frame in the light of future contingencies and uncertainties. The difference in PVRR between the portfolios with CCs early and those with CTs early ranged from 0.1% to 0.5% over the 35-year study period. In light of this relatively small difference in PVRR, it is appropriate to give substantial consideration to the benefits of CCs under different scenarios and operating conditions. The Commission concludes that, in light of the Company's plans to retire approximately 1,000 MW of older coal units, the prospects for future carbon regulation, and the other benefits cited herein, the certification of gas-fired CC facilities appropriately serves the public convenience and necessity.

The Commission rejects the argument that the Company should only be allowed to add CT units at the Buck and Dan River sites. For the reasons discussed above, the Commission concludes that Duke's decision to add intermediate CC units instead of only peaking CT units in the relevant time frame is reasonable. The Commission concludes that the Company conducted a reasonable analysis of potential technologies and that the technology proposed by Duke is an appropriate technological option for its new intermediate generation needs in the 2011-2012 time frame.

Finally, Duke plans to phase-in the Buck and Dan River Combined Cycle Projects under continuous construction. Witness Hager testified that the Company has chosen to stage the implementation of the Projects to smooth the "lumpiness" of the generation additions. The Buck Project will begin operation in 2010 with the two CTs operating in simple cycle in time to provide capacity for the summer peak season. During the fall of 2010, the remainder of the equipment will be added to convert these CTs into a combined cycle plant in time for summer of 2011. This plan provides 316 MWs of simple cycle CT capacity for 2010 and 620 MWs in 2011 (again, this plan also includes an additional 632 MW CT facility for which the Company has not yet sought approval), bringing the reserve margin to just over 17% in both of these years. The Company proposes to repeat this process with the Dan River Project in 2011 and 2012.

Public Staff Witness Lam testified that phasing-in the projects as CTs in the first year and CCs in the following year is an efficient use of plant to meet both the capacity and energy requirements set out in the 2007 Annual Plan for that time frame.

The Commission concludes that the phased-in approach for the timing of the Buck and Dan River Combined Cycle Projects proposed by Duke is appropriate and consistent with the public convenience and necessity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence in support of this finding of fact is found in the 2007 Duke Annual Plan, the testimony and exhibits of Duke witness Hager, and the testimony of Public Staff witness Hinton.

Witness Hager testified concerning the Company's consideration of DSM, EE, and renewable resources in its 2007 Annual Plan and in connection with its decision on the Buck and Dan River Combined Cycle Projects. Witness Hager testified that the 2007 Annual Plan reflects modeling of the costs and impacts of DSM and EE (excluding pilot programs) and assumes that these costs and impacts will continue throughout the planning period. Under the 2007 Annual Plan Reference Case, the selected portfolio included 1,016 MW of DSM and 790 MW of EE. Under the Carbon Case, the selected portfolio contained 1,016 MW of DSM, 790 MW of EE, and 1,135 MW of renewable resources.

Witness Hager testified that only EE programs serve as a possible substitute for CC units. DSM programs are a potential substitute for peaking generation only. She testified that the Company based the availability of EE to meet its needs on a market potential study conducted for the Company. The study concluded that the achievable level of EE over the next 5 years was 1.5% of total energy usage. For IRP purposes, the Company included the level of EE that the independent market potential study found reasonably achievable over the near term and assumed that this rate of achievement will continue over time. Witness Hager testified that there is no basis to assume that significantly more EE is available in the time frame when the Buck and Dan River Combined Cycle Projects are needed.

Public Staff Witness John R. Hinton testified that he does not believe that there are additional cost-effective EE and DSM opportunities that would allow Duke to offset or delay the building of the Buck and Dan River Combined Cycle Projects.

With respect to renewables, witness Hager testified that Duke's 2007 Annual Plan reflected North Carolina's recent enactment of a renewable portfolio standard (RPS). She testified that Duke did not select renewables to serve the needs to be met by the Buck and Dan River Combined Cycle Projects because the resource screening performed as part of the IRP process demonstrated that renewables are generally not economical in the absence of a RPS. The 2007 Annual Plan includes sufficient renewables to meet the RPS and assumes that the North Carolina RPS standard will apply to all Duke's sales. Witness Hager testified that it would not be economical for customers to include additional renewables.

The Commission concludes that Duke's need for intermediate generation cannot be met through a combination of DSM, EE, and renewables and that Duke reasonably evaluated these options before filing its CPCN applications herein. While G.S. 62-2(3a) requires evaluation of the full spectrum of DSM and EE, the goal of such an analysis is to ensure that energy planning results in the least cost mix of generation and demand reduction.

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

The evidence in support of these findings of fact is found in the testimony and exhibits of Duke witnesses Hager and Fallon, Public Staff witness Maness, and LS Power witness Willick. These findings deal with evaluation of the wholesale market.

In May 2007, Duke issued a Request for Proposals (RFP) seeking conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 time frame and up to 2000 additional MW beginning in the 2013 time frame. The RFP allowed bids for purchase power agreements (PPAs) or the purchase of existing or new generation assets. Witness Fallon testified to the details of this RFP process. He testified that the Company placed no restrictions on the term of any PPAs other than a one year term minimum. Duke notified all potential bidders that it planned to submit self-build options in this RFP. The RFP specified that the northern region of Duke's service territory was preferred for new resource additions and provided a map of the preferred area. Duke retained Burns & McDonnell Corporation (Burns & McDonnell) to serve as an independent third-party facilitator with respect to the May 2007 RFP. Burns & McDonnell issued the RFP, made exclusive initial contact with all bidders, answered bidder questions prior to submission of the bids, and received all bids from bidders (including the Duke self-build bids). After it had received the bids, reviewed them, and verified any outstanding information, Burns & McDonnell provided redacted copies of the bids, excluding names and locations, to Duke for evaluation.

Public Staff witness Maness testified that the Company's RFP document was detailed and thorough and that it provided bidders with flexibility in how they could bid. The Public Staff had a telephone conference with Burns & McDonnell as part of its investigation in these dockets. Witness Maness testified that Burns & McDonnell facilitated communications between the bidders and the Company on an anonymous basis, received all of the RFP bids, and provided them on an anonymous basis to the Company to ensure a "blind" process. Mr. Maness testified that use of a third-party facilitator adds a valuable control to the RFP process, since it can help to preclude favoritism toward either the self-built options or particular bidders. However, he noted that maintaining the confidentiality of the self-build information still depends on the controls in place as to the flow of information between the Duke teams. Mr. Maness testified that an independent facilitator brings value to the process in terms of assuring independence and making sure that the economics are considered objectively, but that a trade-off could occur in the loss of some of the utility's knowledge and expertise with regard to its own system.

LS Power witness Willick testified that independent third-party oversight of an RFP process is necessary to ensure that there is no bias in favor of any party and that the best resource alternative is selected. He testified that Duke's process did not have this type of oversight. He testified that he would have had Burns and McDonnell involved all the way through the selection of the short list and the further evaluation of any modified bids; under his preferred approach, the utility would still make the final selection, albeit subject to some risk of cost recovery disallowance if it went against the recommendation of the independent evaluator.

Witness Hager testified that ten bidders submitted a total of forty-five bids spanning time periods of two to thirty years in response to Duke's RFP. Witness Fallon testified that, after receiving the redacted bids from Burns & McDonnell, Duke evaluated the redacted bids and developed a short list for further discussion. At that point, Duke requested release of the names of the bidders so Duke could engage in negotiations with the selected bidders. Duke included the LS Power bid on its short list. In preparing the short list, Duke's transmission planning personnel evaluated all bids to determine their ability to address transmission stability concerns in the northern region. Bids that offset the need for alternative transmission investment received a credit equal to the value of that avoided investment. The economic benefits for each bid were summarized and provided to Duke's bid evaluators on an anonymous bidder basis. The LS Power bid received the highest credit in the network transmission component of the evaluation.

Duke witness Fallon testified that, after the details of LS Power's bid were received, it was determined that the LS Power bid had significant limitations, such as a maximum of one daily start and long advance start-up times, and that, unless a PPA could be structured to give Duke the same level of control as it would have over a utility asset, the LS Power bid would not provide the same level of benefit to the northern region as a Duke-owned unit. Witness Fallon testified that an examination of LS Power's mark-up of the PPA showed significant differences in areas such as credit and performance factor. Mr. Fallon testified that LS Power's credit proposal differed, when evaluated conservatively, by a factor of ten from the credit security that Duke would typically require, and he quantified the impacts of the increased security requirement that would result from acceptance of the LS Power bid to be at least $100 million. Mr. Fallon also testified that LS Power's mark-up of the performance factor would reduce LS Power's incentive to be online at the time of system peak by approximately 40%. Witness Fallon testified that the Company did not make a counter proposal in response to LS Power's mark-up because, in the Company's experience, "when you're this far apart on an issue as important as credit that there was very little chance you were going to get there."

Witness Fallon testified that Duke requested all short-listed bidders, including LS Power, to refresh their bids and asked bidders who were offering PPAs to provide bids with terms of 15 years or less. The purpose of the refreshed bids was to provide the bidder an opportunity to update its bid based on more recent cost and market information and to allow Duke the opportunity to get clarity from the bidders about what costs were included. Witness Fallon testified that the Company chose 15 years as the maximum term for the refreshed PPA bids because it had already received a very competitive 15-year bid and because it had received guidance that 15 years was the maximum term to avoid impacts to the Company's balance sheet based on classifying the PPA as a capital lease.

Witness Fallon testified that the self-build bids for the Buck and Dan River Combined Cycle Projects and the LS Power PPA bid all increased in price after they were refreshed. Mr. Fallon testified that the Company's evaluation of the refreshed bids revealed that the Buck and Dan River Combined Cycle Projects were the lowest cost combined cycle bids that helped to mitigate transmission stability concerns in the northern region. The LS Power bid was the highest cost proposal. The Company determined that there were lower cost options than LS Power's bid that also supported the northern region's transmission reliability concerns, as well as options that provided greater operational flexibility and more favorable contract terms. Mr. Fallon testified that the Company did not provide LS Power with a counter-proposal or discuss the deficiencies it found with LS Power's initial 30-year bid with LS Power. He testified that the Company is negotiating a short-term PPA with another third-party owner of a CC facility because it offered the lowest short-term cost, near-term availability, and the flexibility of a shorter term, 3 or 5 years.

Witness Fallon testified that Duke conducted a subsequent evaluation of the bids as a result of the Public Staff's request to update the Company's analysis to assume an 11% return on equity (ROE) as a result of the Company's most recent rate case. The original 2007 RFP analysis contained a 12.5% ROE assumption based on the allowed ROE at the time the RFP was issued. In addition, the Company updated the analysis to use a 4% escalation rate for new capacity consistent with the 2007 IRP assumption. The original 2007 RFP analysis contained a 2.3% escalation. Witness Fallon testified that this revised analysis shows that the Projects are still the lowest-cost bids that help mitigate transmission stability concerns in the northern region.

Public Staff witness Maness testified that, after receiving the redacted bids from Burns and McDonnell, the Company worked to create a short list in three categories: long-term CC, long-term CT, and short-term purchases. Duke notified the "winning" bidders in each category that they had been included on the short list and began discussing additional details regarding the pricing and terms of potential arrangements with each bidder. Duke also allowed each short-listed bidder to refresh the pricing and other terms of its bid in order to take into account any changes that might have occurred since the initial bid. As part of this refreshing process, Duke asked the CC bidders to provide pricing and other terms for an arrangement of no more than 15 years in length. Mr. Maness testified that one of the more competitive bidders that had proposed a unit in the area preferred by Duke did not offer a term of 15 years or less and was removed from the short list. Another preferred-area competitive bidder did offer a 15-year term, but Duke's analysis showed that its costs had become higher than the self-build options. One non-preferred-area bidder offered a competitive price for a 10-year term for CC power, and Duke has chosen to proceed to further negotiations with that bidder. Mr. Maness also testified that the Company began discussions with the short-listed CT bidders but did not proceed with any of these discussions beyond early December 2007. Mr. Maness testified that, as a result of the RFP process, Duke decided to pursue the construction of the Buck and Dan River Combined Cycle Projects, resulting in the Company's applications herein.

There was extensive testimony and cross examination regarding the Company's general willingness or unwillingness to enter into a 30-year PPA. LS Power's initial bid was for a PPA with a 30-year term, and it was the only 30-year PPA bid that Duke received in response to the RFP. Company witness Hager testified that the Company does not have any CC PPAs with a term greater than 15 years.

LS Power witness Willick testified that LS Power was made aware of Duke's desire for a term no longer than 15 years only at the time Duke asked LS Power to refresh its bid and that this was the only time in his experience that this type of event had occurred. Mr. Willick testified that LS Power has entered into several agreements with terms between 20 and 30 years, but that a contract of 15 years was not outside the industry norm. Mr. Willick testified that the cost of LS Power's bid increased when it was refreshed to a maximum term of 15 years because LS Power chooses to finance its projects on a project finance basis, which means that they "try to amortize the entire project cost or as much as practical under the term of the purchase power agreement."

Duke witness Fallon testified that the generation asset that LS Power proposed to build as part of its PPA bid would have residual value after the end of the 15-year term of the PPA because LS Power could sell into the wholesale market, and that it appeared to him that LS Power tried to apportion a lot of the risk related to the residual value to Duke and its customers in its refreshed 15-year PPA bid. On cross-examination, witness Fallon disagreed with the assumption that shortening the term of a PPA bid would increase its cost and testified that another bidder's cost had increased when its term was extended. Witness Fallon testified that Duke does not have a blanket opposition to considering a PPA of greater than 15 years. However, in this particular case, because of the critical importance of the resource to provide voltage support in the northern region and LS Power's initial mark-up of the PPA, the Company did not believe that it could reach acceptable terms for 30 years. Witness Fallon testified that LS Power's initial bid had some value, so it was asked to refresh the bid with a maximum term of 15 years to allow the parties potentially to come to terms on the areas where there were major differences. Duke did not eliminate the LS Power bid because it was a 30-year PPA, but because Duke did not believe it could agree to terms after seeing LS Power's mark-up. In addition, after seeing LS Power's mark-up, it became clear that the LS Power bid would not provide the same operational benefit as needed, so it lost the economic value of its original transmission system benefit. Witness Fallon testified that, while some risk can conceivably be addressed in contract terms, there would be a price associated with doing that, and he emphasized that "having a letter of credit doesn't keep the lights on."

Witness Maness testified that it appeared that Duke's RFP was conducted well and that it resulted in a number of bids that were competitive with the Company's self-build alternatives. Mr. Maness testified that the Public Staff believes that Duke acted reasonably and within its discretion to limit the refreshed bids to a maximum of 15 years, but he also testified to his concern that restricting PPA arrangements to a maximum of 15 years without further investigation may have precluded the availability of some competitively priced generation. Two CC bidders proposing facilities in the area preferred by Duke were effectively eliminated because of Duke's insistence on a 15-year limitation. Duke has indicated that PPAs longer than 15 years expose the Company to risks related to operational reliability, dispatch limitations, credit, survival of the selling business entity, and loss of residual life benefits, and Mr. Maness agreed that these are legitimate factors. However, he encouraged Duke to investigate ways to mitigate these risks so as to preserve the benefits offered by contracts longer than 15 years.

Mr. Maness also expressed some concern that, if the Company executes the PPA currently under negotiation with a third party, it would have more CC capacity in the near term than called for in the 2007 Annual Plan. He stated that, since the CC generation in the Annual Plan is fulfilled by the Buck and Dan River Combined Cycle Projects and since the quantitative analysis in the Annual Plan supported short-term CT additions, Duke should be aware that the prudence of any additional contract for CC capacity would be subject to review in a future ratemaking proceeding. In response, witness Hager stressed the importance of preserving options to ensure that customers' needs can be met.

Finally, witness Willick testified that the RFP process was not fair and transparent enough, but he admitted that LS Power had not complained to Duke prior to intervening in these dockets. Witness Fallon testified that no other bidder complained or expressed concerns to Duke or Burns & McDonnell about the 2007 RFP.

The Commission has carefully considered whether Duke appropriately evaluated the wholesale market before deciding to proceed with the Buck and Dan River Combined Cycle Projects. As a foundation for this consideration, the Commission first reviewed the guidance concerning evaluating wholesale market alternatives that has been given to public utilities either by statute or by the Commission's rules and prior orders.

Regulatory recognition of the part to be played by the wholesale market in electric utilities' resource planning has its roots in G. S. 62-110.1(d), which provides:

> In acting upon any petition for the construction of any facility for the generation of electricity, the Commission shall take into account the applicant's arrangements with other electric utilities for interchange of power, pooling of plant, purchase of power and other arrangements for providing reliable, efficient and economical electric service.

However, neither the statute nor original Commission Rules R8-60 and R8-61 required that an electric utility conduct a survey of the wholesale market or show that it had done so as part of a CPCN application.[1] The issue was addressed by the Commission in Docket No. E-2, Sub 733, a 1999 CPCN application by Carolina Power and Light Company (now Progress Energy Carolinas, LLC) for CPCNs authorizing construction of 800 MW of CT capacity in Rowan County and 800 MW of CT capacity in Richmond County. The Public Staff expressed concern that as to the utility's "apparent step away from explicit consideration of the wholesale market...." In its Order Granting Certificates issued on November 2, 1999, the Commission concluded that it was appropriate to issue the CPCNs, but addressed the evaluation of the wholesale market as follows:

> The Commission fully supports and concurs in the Public Staff's concern that the electric utilities of this State must properly assess the capabilities of the wholesale market when making resource additions that will be used to serve CP&L's retail customers. The Commission is of the opinion that there continue to be benefits potentially available to electric utilities from looking to the wholesale market for generation resources, and that utilities regulated by the Commission should make every effort to do so for possible sources of capacity and energy to serve their retail customers. Therefore, the Commission concludes that CP&L should fully consider the wholesale market for future generation resource additions that will be used in whole or in part to serve retail customers, whether by formal RFP or other measures that ensure a complete evaluation of the market.

89th Report of the North Carolina Utilities Commission Orders and Decisions 253, 259 (1999).

In this case, Duke conducted an RFP, but concerns have nonetheless been raised as to whether Duke's actions were such as to "ensure a complete evaluation of the market." Duke presented evidence that its RFP and bid evaluation process were fair, that the initial LS Power bid presented concerns regarding credit security and performance limitations, that the refreshed

[1] Rules R8-60 and R8-61 were amended in March of 2008. One amendment added a specific requirement that an electric utility's IRP process include an assessment of "the potential benefits of soliciting proposals from wholesale power suppliers and power marketers to supply it with needed capacity." Rule R8-60(d). The amendments did not become effective until after Duke's 2007 Annual Plan and the filing of the applications herein.

bid was rejected on cost, and that the Company did not make a counter proposal because the parties were so far apart. LS Power complains that the objections Duke has identified with its initial bid could have been addressed by contract negotiations, but that Duke instead speculated that the parties would not be able to agree and made no attempt to negotiate. Further, LS Power argues that Duke "changed the RFP terms mid-process by imposing a 15-year maximum length for [PPAs], thereby increasing the per-unit cost of those proposals." It argues that Duke's self-build options only became economical <u>after</u> this change was made. EPSA goes further: it charges that Duke "not only changed the evaluation metrics mid-stream to benefit its self-build bid, but that the utility never intended to consider alternatives to its supply options to begin with."

The Commission notes that Duke tested the wholesale market with an RFP and that Duke used a third-party facilitator, which has not been previously required, for part of the RFP process. The Commission believes that the credit and performance concerns raised by Duke with respect to LS Power's initial bid were significant: the credit concerns were quantified at $100 million and the performance concerns seriously compromised the bid's benefits to the preferred northern region. The Commission cannot conclude that Duke was obligated to negotiate with LS Power given these facts, and we note that LS Power did not initiate negotiations either. On the other hand, the Commission shares some of the concerns raised by the intervenors. The original RFP did not limit PPAs to 15 years; this requirement was imposed after initial bids were received, and it effectively changed the rules of the RFP in a very significant way. Negotiations might, or might not, have resulted in terms that would have satisfactorily protected the Company from the risks that Duke identified in the mark-up of the initial LS Power bid. The Commission recognizes that it has given only general guidance as to what would constitute an adequate evaluation of market alternatives. The Commission also recognizes the demonstrated need for new capacity and the time frame of that need. Weighing all of these circumstances, the Commission concludes that Duke adequately evaluated the wholesale market for purposes of this proceeding and that CPCNs should be granted. However, the Commission recognizes that for the State's electric utilities to properly assess and realize the advantages of the wholesale market, the rules and procedures employed for soliciting and analyzing RFPs must be fair and transparent. Participation in the wholesale market by participants such as LS Power can be a time consuming and expensive process. If the procedures are too onerous and the chances of success too low, participation will be discouraged and the benefits left unrealized. Therefore, as recommended by LS Power and other intervenors, the Commission will consider whether it should give further guidance or adopt more specific rules as to how electric utilities should assess the capabilities of the wholesale market when making resource additions and, if so, what the components of such guidance or rules should be. The Commission will, in the near future, institute a rulemaking proceeding in a new docket for this purpose.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence in support of this finding of fact is found in the testimony of Duke witnesses Ruff, Hager, Landseidel, and Fallon and Public Staff witness Lam.

Company witness Ruff testified that the Buck and Dan River Combined Cycle Projects will be the first combined cycle units on the Duke system and will be the most efficient natural gas units in the Company's generation portfolio.

Witness Landseidel testified that the Projects will provide additional operational flexibility that does not currently exist due to their ability to start up and reach full load more quickly and their shorter required minimum run time when compared with the Company's older coal units, which currently operate to serve intermediate load.

Witness Hager testified that Duke currently has approximately 3,000 MW of gas-fired CTs, but no CCs, and that gas-fired generation currently comprises 15% of the Company's capacity and approximately 0.5% of its energy mix. With the addition of the Buck and Dan River Combined Cycle Projects, the Company's gas-fired generation will comprise 19% of its available capacity and 2.5% of its energy output. With all of the gas additions in the 2007 Annual Plan, gas-fired generation will comprise 26% of available capacity and 5% of energy output by 2027. Witness Hager testified that this is a reasonable level of reliance on natural gas as part of a diverse resource mix.

Witness Landseidel testified that Duke is negotiating a long-term firm gas transportation agreement with Transco and that there should be sufficient gas supply available for both the Buck and Dan River Combined Cycle Projects.

The Commission is interested in ensuring that the Company has a reliable fuel supply for both the Buck and Dan River Combined Cycle Projects, so the CPCNs granted herein shall be conditioned upon Duke continuing to pursue appropriate long-term, firm natural gas transportation arrangements for the Projects.

Witness Ruff testified that the location of the Buck and Dan River Combined Cycle Projects will provide system voltage stability for Duke's growing northern region.

Company witness Landseidel also testified to the significant new load growth in the northern region and the voltage stability issue. He stated that both the Buck and Dan River Combined Cycle Projects are needed and will feed real and reactive power into the northern region transmission network to help support and eliminate the existing voltage stability issues. Witness Landseidel also testified that siting CTs at the Buck and Dan River sites, instead of CCs, would not provide as much voltage support because CTs operate fewer hours and are typically limited to fewer hours by their operating permits.

Likewise, Company witness Fallon testified that both Projects are needed to help support voltage in the northern region. Witness Fallon explained that if, for some reason, only one of the Projects were approved by the Commission, "there would be significant alternative transmission investment that would be needed that would help the situation but would not provide as much value as generation in that area."

Public Staff witness Lam testified that the Company has a large and growing load in its northern region, which includes the cities of Greensboro, Winston-Salem, Chapel Hill, Durham, and High Point, which, combined with a lack of sufficient generation resources in that area, could cause system stability problems in emergency conditions such as the loss of one of the Belews Creek units or the loss of certain transmission lines. Witness Lam testified that the Company has met with the Public Staff numerous times over the past decade to discuss the situation in the northern region. He testified that the Company is proposing to install static VAR compensators to help compensate for the lack of sufficient generation in the northern region during emergency conditions but that the construction of new generation in the northern region is the only long-term answer to these transmission stability issues. Witness Lam testified that construction of the Buck and Dan River Combined Cycle Projects is the best solution for this problem.

The Commission concludes that the voltage stability issue in the Company's northern region was an important factor in the decision to add the Buck and Dan River Combined Cycle Projects and that the Projects will address these reliability issues.

As part of the addition of the Buck Combined Cycle Project, Duke plans to retire the existing Buck coal-fired Units 3 and 4 (totaling 113 MW), which began operation in 1941 and 1942, respectively. As part of the Dan River Combined Cycle Project, the Company plans to retire the existing Dan River coal-fired Units 1 and 2 (totaling 134 MW), which began operation in 1949 and 1950, respectively. Witness Ruff testified to the Company's plans to retire approximately 1,000 MW of older, less-efficient coal capacity as part of the approval of the addition of the 800 MW Cliffside Unit 6. The units that will be retired are the least efficient coal units in the Duke fleet and operate as peaking or intermediate resources. The Buck and Dan River Combined Cycle Projects will operate as intermediate resources and will provide efficient, low-emission alternatives to these retired coal units.

Witness Hager testified that the Buck and Dan River Combined Cycle Projects are the best replacements for the intermediate load, older coal units that will be retired.

The Commission concludes that the fleet modernization benefits are significant factors supporting the decision to construct the Projects.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence in support of this finding of fact is found in the verified applications and in the testimony and exhibits of Duke witness Landseidel.

Witness Landseidel testified that the Buck and Dan River Combined Cycle Projects will feature state-of-the-art emissions controls. The Projects will use combustion turbines with dry low NOx combustors to minimize the formation of NOx and will operate with this level of control in simple cycle operation. Beginning with combined cycle operation, there will also be a selective catalytic reduction system in the heat recovery steam generators to further reduce NOx emissions. Because Rowan County is part of an eight-county region that has been designated as "moderate" non-attainment for ozone, the design of the Buck Combined Cycle Project also incorporates an oxidation catalyst in the heat recovery steam generators to reduce carbon monoxide and volatile organic compound levels. The design of the Dan River Combined Cycle Project incorporates space for future addition of an oxidation catalyst.

Witness Landseidel also testified to the use of cooling towers in the design of the Projects to minimize both the intake and discharge impacts to the Yadkin and Dan Rivers. The Company has decided to retain the condenser cooling water pumps for the to-be-retired Buck coal-fired Units 3 and 4 to supply the existing Buck coal-fired Units 5 and 6 and to prevent generation curtailments due to periods of high temperature discharges. The Company will restrict the total withdrawal from the Yadkin River during such extreme periods to the current plant operation withdrawal levels. The maximum flow requirement from the Dan River is approximately 5% of that for the existing Dan River Units 1 and 2, which will be retired as part of the project. Witness Landseidel also testified to the status of the related environmental permits to be issued by other agencies.

No intervenor raised any issue with regard to the environmental impacts of the Projects. The Commission concludes that Duke has appropriately considered impacts to the environment in its proposals.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence in support of this finding of fact is found in the testimony and exhibits of Duke witness Landseidel, Duke's late-filed exhibits, the testimony of Public Staff witness Lam, and the testimony of public witness Ann Brownlee.

Witness Landseidel testified to the comprehensive siting study that Duke conducted in 2005 to determine the optimum siting locations for new fossil-fired generation. The study considered 24 potential sites and a number of siting criteria, including gas supply, electric transmission interconnection, water supply, environmental impacts, land use, existing infrastructure, cultural resources, and public impacts. The study recommended the Company's existing Buck Steam Station site and the existing Lee Steam Station site in South Carolina for new intermediate load generation. The Company filed preliminary CPCN information in 2005 for a Buck Combined Cycle Project. Witness Landseidel testified that, since the 2005 study, the only key intermediate generation siting variable that has changed is a preference for new generation resources to be located in the northern and central portions of North Carolina due to load growth and system voltage stability issues in the northern portion of the Duke service territory. Considering this transmission factor, the 2005 study was updated in early 2007, and the Company selected the Buck and Dan River sites over the Lee site, which is located at the extreme southern portion of the Company's South Carolina service territory. Because both the Buck and Dan River sites are existing generating stations, critical infrastructure is already in place, which keeps construction and operating costs lower and minimizes environmental impacts. Duke has a long-established presence in both communities and has received strong local support for the Projects.

Public Staff witness Lam testified that he had personally visited the Buck and Dan River sites and that the locations are excellent choices for new gas-fired CC units. He testified that each site is a brownfield generating site with existing infrastructure such as a transmission network and switching station, gas pipelines, railroad unloading facilities, cooling water availability, and other station requirements. Lam concluded that use of the existing Buck and Dan River sites should result in a lower cost of building the units.

Ann Brownlee, president of the Trading Ford Historic District Preservation Association, testified as a public witness at the February 28, 2008 public hearing in Salisbury. Trading Ford refers to an area about four miles along the Yadkin River. Witness Brownlee expressed concerns about injury to the historic and cultural significance of the Trading Ford area, which is in the vicinity of the Buck Steam Station, particularly as relating to a Revolutionary War skirmish in the area and a crossing of the Yadkin River used in the 18th century and before. She acknowledged the cultural resources survey prepared by Duke's consultants pursuant to Section 106 of the National Historic Preservation Act of 1966, but testified that the report "sidestepped evaluating the Revolutionary War site." Witness Brownlee testified that the Revolutionary War site was part of a 230-mile trek across North Carolina by General Nathanael Greene in 1781 and that the proposed generating facility would be located "right smack in the middle" of the Revolutionary War site. She testified that a National Park Service study of the entire 230-mile corridor is under way. Ms. Brownlee has, on several occasions both before and after the hearings herein, sent additional materials and correspondence related to her concerns to the Commission

Witness Landseidel testified that Duke has held discussions with Ms. Brownlee for a number of years regarding her concerns. Witness Landseidel testified that the Company engaged a cultural resources consultant, Brockington & Associates, which surveyed the proposed generating site and prepared a report, which concluded that the Buck Combined Cycle Project would not impact cultural resources. The report recommended "cultural resources clearance for the project tract." Witness Landseidel testified that this report was submitted to the North Carolina State Historic Preservation Office (SHPO) and that SHPO issued a December 5, 2007 letter to the effect that the one archaeological site found in the survey was not eligible for listing in the National Register of Historic Places and that the tract does not possess the potential to yield significant new information on the history or prehistory of North Carolina. Duke filed the Brockington & Associates report as Late-Filed Ex. 1 and the December 5, 2007 letter from SHPO as Late-Filed Ex. 2.

The Commission concludes that Duke conducted a comprehensive study and selected appropriate sites for the Buck and Dan River Combined Cycle Projects. The Commission appreciates the contribution that public witness Brownlee has made to this process, and the Commission commends her for her efforts to raise awareness of the significance of the Trading Ford site. The Commission, however, has neither the expertise nor the statutory authority to resolve the issues raised by Ms. Brownlee. In proceedings such as this one, the responsibility of the Utilities Commission is to address issues such as those delineated in the High Rock Lake case that was discussed above in connection with earlier findings of fact. When raised, issues of historical preservation, and also issues of environmental permitting, are traditionally left to the State and federal agencies that have been given statutory responsibility for addressing such issues. Ms. Brownlee acknowledged at the hearing that she "assumed that it would be handled through those channels" but testified that she wanted to call the Commission's attention to the historic preservation issues. The Commission appreciates her testimony herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence in support of this finding of fact is found in the testimony and exhibits of Duke witnesses Landseidel and Hager and the testimony of Public Staff witness Lam.

Duke submitted confidential cost estimates for the Buck and Dan River Combined Cycle Projects under seal pursuant to G.S. 132-1.2. Public Staff witness Lam testified that the Projects will supply capacity and energy at a reasonable estimated cost. No specific issue was raised as to the validity of the Company's cost estimates.

The Commission finds and concludes that the Company has reasonably forecasted the costs associated with the Buck and Dan River Combined Cycle Projects as discussed in the testimony of witnesses Hager and Landseidel and that the cost estimates for the Buck and Dan River Combined Cycle Projects are reasonable and are approved. The Company shall update the cost estimates during construction on an annual basis as required by G.S. 62-110.1(f).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The Commission concludes from the record herein that construction of the Buck and Dan River Combined Cycle Projects is required by the public convenience and necessity and that CPCNs for the Projects should be issued. It has been demonstrated that Duke's customer base is growing, that the Company is taking steps to modernize its generation fleet through the retirement of older, less-efficient coal-fired units, and that the Company needs additional generation resources. In order to reliably meet the growing power supply needs of the State in the 2010 to 2012 time frame, Duke must take steps now to begin construction of the Buck and Dan River Combined Cycle Projects on the phased-in approach proposed by the Company.

The Company does, however, face many uncertainties, since the planning environment has never been more dynamic. In order to address uncertainties related to the supply of natural gas, the CPCNs issued herein are conditioned upon the Company's continuing to pursue appropriate long-term, firm natural gas transportation arrangements for the Buck and Dan River Combined Cycle Projects. Based upon all of the evidence contained in the record of this proceeding, and with the conditions contained in the Ordering Paragraphs below, the Commission concludes that Duke has met its burden of showing that construction of the Buck and Dan River Combined Cycle Projects is required by the public convenience and necessity. The Company shall submit annual progress reports during construction pursuant to G.S. 62-110.1(f), as well as annual resource plans pursuant to Rule R8-60.

IT IS, THEREFORE ORDERED:

1. That the applications filed in this docket should be, and the same hereby are, approved and Certificates of Public Convenience and Necessity for the natural gas-fired Buck and Dan River combined cycle facilities, and related transmission facilities, are hereby granted and this order shall constitute the certificates;

2. That Duke shall retire Buck Unit 4 no later than the commercial operation of the Buck project approved herein in simple cycle mode and shall retire Unit 3 no later than the

commercial operation of the Buck project approved herein in combined cycle mode; and that Duke shall retire Dan River Unit 1 no later than the commercial operation of the Dan River project approved herein in simple cycle mode and shall retire Unit 2 no later than the commercial operation of the Dan River project approved herein in combined cycle mode;

3. That Duke shall continue to pursue negotiations for appropriate long-term, firm natural gas transportation arrangements for the Buck and Dan River Combined Cycle Projects;

4. That Duke shall file with the Commission in this docket a progress report and any revisions in the cost estimates for the Buck and Dan River Combined Cycle Projects on an annual basis, with the first such report due no later than one year from the date of this Order;

5. That, for ratemaking purposes, the issuance of this Order does not constitute approval of the final costs associated therewith and that the approval and grant is without prejudice to the right of any party to take issue with the treatment of the final costs for ratemaking purposes in a future proceeding; and

6. The Commission will, in the near future, institute a rulemaking proceeding in a new docket for the purpose of considering whether it should give further guidance or adopt rules with greater specificity as to how electric utilities should assess the capabilities of the wholesale market when making resource additions and, if so, what the components of such guidance or rules should be.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of June, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc060508.01

Commissioner James Y. Kerr, II did not vote on this decision.

DOCKET NO. E-7, SUB 819

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC for Approval of Decision to Incur Nuclear Generation Project Development Costs	)))	ORDER APPROVING DECISION TO INCUR PROJECT DEVELOPMENT COSTS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, April 29, 2009, at 9:00 a.m.

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Robert V. Owens, Jr., Sam J. Ervin, IV, Lorinzo L. Joyner, Howard N. Lee, and William T. Culpepper, III

APPEARANCES:

For Duke Energy Carolinas, LLC:

Lawrence B. Somers, Associate General Counsel, Duke Energy Corporation, Post Office Box 1006, Charlotte, North Carolina 28201-1006

Robert W. Kaylor, Law Offices of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 160, Raleigh, North Carolina 27603

For Carolina Industrial Group for Fair Utility Rates III:

Ralph McDonald, Bailey & Dixon, LLP, Attorneys at Law, Post Office Box 1351, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc:

Robert F. Page, Crisp, Page & Currin, LLP, Attorneys at Law, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609-6622

For Public Advocacy Groups:

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

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff, 4326 Mail Services Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: On December 7, 2007, Duke Energy Carolinas, LLC (Duke or Company) filed an Application for Approval of Decision to Incur Continued Nuclear Generation Project Development Costs. By its application, Duke seeks authority to incur additional project development costs of up to $160 million for the period January 1, 2008, through December 31, 2009, for the Company's proposed Lee Nuclear Station in Cherokee County, South Carolina. Duke filed this application pursuant to G.S. 62-60, G.S. 1-253, G.S. 62-2, G.S. 62-110.7, and prior Orders of the Commission entered in this docket. As to G.S. 62-110.7, Duke acknowledged that this statute did not become effective until January 1, 2008, but requested that the Commission deem its application to have been filed pursuant to that statute as of January 2, 2008, or provide advice as to whether the Company should refile its application at that time.

In response to the application, the Commission issued an Order on December 11, 2007, scheduling it for hearing to begin on April 29, 2008, and requiring the prefiling of testimony. The application was deemed to have been filed on January 2, 2008, pursuant to the provisions of G.S. 62-110.7, and the 180-day time period set forth in G.S. 62-110.7(b), as applied to this pending application, was determined to begin running from January 2, 2008.

The petitions to intervene previously filed in this docket were recognized. These included petitions by the Carolina Utility Customers Association, Inc. (CUCA), the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III), and the Public Advocacy Groups (the Groups).[1] The Attorney General's previously-filed notice of intervention pursuant to G.S. 62-20 was recognized, and the intervention of the Public Staff was recognized pursuant to Commission Rule R1-19(e).

On March 4, 2008, the Groups filed a motion requesting that the Commission require Duke to publicly disclose its current cost estimate for the proposed Lee Nuclear Station, including allowance for funds used during construction (AFUDC) and other financing charges, and to publicly disclose on a quarterly basis any changes in those cost estimates. The cost estimate confidentially provided by Duke to the Groups in response to their data request was attached to the confidential version of the motion requesting disclosure.

On March 19, 2008, Duke filed a response in opposition to the motion, asserting that the "confidential information" exception to the North Carolina Public Records Act set forth in G.S. 132-1.2(1) protects the Lee Nuclear Station cost information from immediate public disclosure. Duke attached the affidavit of Bryan Dolan, Vice President of Nuclear Plant Development for Duke, in support of its position that disclosure of the cost estimates would place Duke at an unfair advantage in negotiations with potential suppliers and would hurt Duke's ability to negotiate the lowest cost for its customers.

[1] The Groups include the following intervenors: N.C. Waste Awareness and Reduction Network (NC Warn), Public Citizen, the North Carolina Public Interest Research Group, the Nuclear Information and Resource Service, Common Sense at the Nuclear Crossroads, Clean Water for North Carolina, and the Blue Ridge Environmental Defense League.

On March 20, 2008, the Commission issued an Order allowing other parties to this proceeding to file comments in response to the motion for public disclosure. The Public Staff and the Attorney General filed comments on April 4, 2008, to which Duke filed a response on April 14, 2008. The Groups filed reply comments, also on April 14, 2008.

On April 22, 2008, the Chairman issued an Order Allowing Affidavits and Argument on Motion for Public Disclosure which gave all parties the opportunity to file affidavits on the motion and scheduled an oral argument. On April 28, 2008, the Groups filed the affidavit of Jim Warren, Executive Director of NC Warn, and a motion to allow the prefiled testimony of Peter A. Bradford to be treated as an affidavit, which was subsequently allowed.

This docket came on for hearing as scheduled. At the beginning of the hearing, Herman Jaffe testified as a public witness.

A hearing was then held on the motion of the Groups for public disclosure of Duke's current cost estimates. Duke was allowed to conduct a *voir dire* as to affiant Warren's qualifications to make the statements in his affidavit. Duke objected to Mr. Warren's affidavit, but the Chairman ruled that Mr. Warren's affidavit and exhibit would be received and given the weight to which they are entitled. Oral argument upon the Group's motion was then heard. Following a recess, the Commission ruled upon the motion as hereinafter discussed.

Duke then presented the direct testimony of Ellen T. Ruff, President of the Company; Janice D. Hager, Managing Director, Integrated Resource Planning and Environmental Strategy for Duke Energy Corporation's operating utilities; and Dhiaa M. Jamil, Group Executive and Chief Nuclear Officer for the Company, who adopted the pre-filed testimony of Henry B. Barron, Jr.

The Public Staff presented the joint testimony of Michael C. Maness, Supervisor of the Electric Section of the Public Staff's Accounting Division, and Kennie D. Ellis, Utilities Engineer with the Electric Division of the Public Staff.

The Groups presented the testimony of Peter A. Bradford, an adjunct professor at Vermont Law School and President of Bradford Brook Associates.

Duke presented the rebuttal testimony of J. Danny Wiles, Vice President, Franchised Electric & Gas Accounting, Duke Energy Business Services; Dhiaa M. Jamil, Group Executive and Chief Nuclear Officer for the Company; and Dr. Julius A. Wright, President of J.A. Wright & Associates.

On May 9, 2008, the Company filed Duke Late-Filed Exhibit No. 1, providing detail behind Duke Energy Corporation's $23 billion capital budget for 2008-2012, as requested by the Commission. On May 19, 2008, Briefs were filed by CUCA and the Groups, and Proposed Orders were filed by Duke and the Public Staff.

As indicated above, the Chairman announced the Commission's decision on the motion for disclosure of Duke's cost estimates for the Lee Nuclear Station at the April 29, 2008 hearing, subject to its being presented in writing in the present order.

RULING ON MOTION FOR PUBLIC DISCLOSURE

G.S. 132-1.2(1), entitled "Confidential information," provides that the Public Records Act does not require or authorize a public agency to disclose information that meets the following conditions:

> (a) Constitutes a "trade secret" as defined in G.S. 66-152(3);
> (b) Is the property of a private "person" as defined in G.S. 66-152(2);
> (c) Is disclosed or furnished to the public agency... in compliance with laws, regulations, rules, or ordinances of the United States, the State, or political subdivision of the State; and
> (d) Is designated or indicated as "confidential" or as a "trade secret" at the time of its initial disclosure to the public agency.

The public records "do not include" information that meets these four conditions. State ex rel. Utilities Comm'n v. MCI Telecommunications Corp., 132 N.C.App. 625, 632 (1999). The term "trade secret" means business, or technical information, including but not limited to, a formula, pattern, program, device, compilation of information, method, technique, or process that:

> (a) Derives independent actual or potential commercial value from not being generally known or readily ascertainable through independent development or reverse engineering by persons who can obtain economic value from its disclosure or use; and
>
> (b) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.
>
> The existence of a trade secret shall not be negated merely because information comprising the trade secret has also been developed, used, or owned independently by more than one person, or licensed to other persons.

G.S. 66-152(3). Case law lists the following factors to consider when determining if information should be protected as a "trade secret":

1) the extent to which information is known outside the business;
2) the extent to which it is known to employees and others involved in the business;
3) the extent of measures taken to guard secrecy of the information;
4) the value of information to business and its competitors;
5) the amount of effort or money expended in developing the information;
6) the ease or difficulty with which the information could properly be acquired or duplicated by others.

MCI, 132 N.C.App. at 634; Wilmington Star-News v. New Hanover Regional Medical Center, 125 N.C.App. 174, 180-81, appeal dismissed, 346 N.C. 557 (1997).

Much of the argument was devoted to the appropriate standard for ruling on the motion. The Groups stated that the trade secret analysis is a good place to start, but "you also have to look at the public interest component." They urged that their motion be viewed "more like a complaint" and that the Commission look to the declarations of policy in G.S. 62-2 and to its discretion. Duke, on the other hand, contended that the analysis in the MCI case is the controlling standard. The Commission agrees with Duke.

Although the cost estimates are not now a public record (having been received by the Commission only as a confidential attachment to the motion, see Virmani v. Presbyterian Health Services Corp., 350 N.C. 449, 467-8 (1999)), allowing the Groups' motion might, in effect, create a public record since the public would then be able to see and use the estimates. Therefore, in ruling on the motion, it is appropriate for the Commission to decide whether the estimates are entitled by statute to protection from disclosure as trade secrets. The Groups' affidavits and argument primarily go to the "public interest" that would be served by disclosure of the estimates; however, the "confidential information" provision of the Public Records Act cannot be construed differently in the context of a regulated industry. See MCI, 132 N.C.App. at 635. The Commission concludes that there is no "public interest" exception to the "confidential information" provisions of G.S. 132-1.2(1). If the cost estimates qualify as a "trade secret" under G.S. 66-152(3), and if they also meet the other conditions of G.S. 132-1.2(1) (which, in this case, is not disputed), then the Commission is not authorized to order that they be publicly disclosed, even if it were otherwise inclined to do so based upon the "public interest" argument. The Commission concludes that this is the appropriate analysis to engage in deciding the motion.

The Commission concludes from the affidavits, testimony, and arguments presented herein that the cost estimates do indeed qualify as trade secrets. At this time, the estimates are not widely known, Duke is taking steps to guard their secrecy, and the estimates have commercial value to Duke because they could be used by suppliers to estimate Duke's anticipated cost of their equipment or otherwise compromise Duke's ability to negotiate the lowest cost. The affidavit presented by Duke supports this conclusion, and the affidavits of the Groups do not convince the Commission otherwise. The Commission concludes that Duke's current cost estimates for the Lee Nuclear Station are, at this time, entitled to protection as confidential information pursuant to G.S. 132-1.2(1). The Commission cannot rule at this time as to when future cost estimates may lose such protection, because such an analysis is fact-specific and must be based upon the circumstances as they exist in the future. However, the Commission believes that it is in the public interest for such estimates to be disclosed at the earliest possible time that disclosure will no longer prejudice Duke's negotiations. The Commission will allow any party to file a new motion for disclosure as Duke's planning and negotiations and construction proceed.

This ruling does not apply to the statement made in open proceedings in South Carolina by Duke CEO James Rogers to the effect that, compared with the $2 billion Cliffside plant, "building a $6-8 billion dollar nuclear plant in Cherokee County will create significantly more jobs." Further, this ruling does not apply to the following statement contained in Duke's discovery to the Groups, which Duke concedes is not a trade secret: "More recent publicly-available industry cost estimates for new nuclear generation are in the range of $3100/kw to $4500/kw (current year dollars, without AFUDC)."

Turning to the Application for Approval of Decision to Incur Continued Nuclear Generation Project Development Costs, based on the evidence presented at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. Duke is a public utility providing electric utility service to customers in its service area in North Carolina subject to the Commission's jurisdiction.

2. The Commission has jurisdiction over this application pursuant to G.S. 62-110.7. This statute allows a utility to request, at any time prior to the filing of an application for a certificate to construct a potential nuclear generating facility to serve North Carolina retail customers, that the Commission review the public utility's decision to incur project development costs.

3. In its July 9, 2007 Order approving Duke's 2006 integrated resource plan in Docket No. E-100, Sub 109, the Commission found Duke's peak and energy forecasts to be reasonable for planning purposes. These forecasts indicated ten-year average annual growth rates of 1.7% in Duke's summer peak and 1.6% in Duke's energy sales. The peak growth rate equates to an annual growth rate of 326 megawatts (MW).

4. Because of load growth, retirements of older generating units, and the expiration of purchased power contracts, Duke's 2007 integrated resource plan (2007 Plan)[1] shows the need for 7,000 additional MW by 2018 and 10,280 MW by 2026.

5. The quantitative analyses in Duke's 2007 Plan suggest that a combination of additional base load, intermediate and peaking generation facilities, renewable resources, energy efficiency (EE), and demand side management (DSM) is required over the next 20 years to meet customer demand reliably and cost effectively.

6. Under both the Reference Case and the Carbon Case in Duke's 2007 Plan, 1,117 MW of nuclear capacity were included in the selected portfolio, with the optimal timing for the capacity to come online varying from 2016 to 2023.

7. The current planning environment is characterized predominantly by uncertainties, such as the effectiveness of new DSM and EE programs, the potential effects on load growth of DSM and EE and increased fuel and building material costs, whether worldwide demand for building materials will continue to cause price increases and lengthened delivery times, whether carbon legislation will be enacted, and, if it is, what form it will take and at what cost, whether and how much renewable energy will become available, how well renewable

[1] The load forecast portion of Duke's 2007 Plan has been set for hearing beginning July 1, 2008.

technologies can be integrated into a utility's resource mix, and the characteristics of the renewable facilities that do come online (e.g. base load versus peaking).

8. Based upon present load forecasts, the uncertainty surrounding the amount and performance of renewable energy, EE, and DSM resources, and the present uncertainty with respect to carbon legislation in the future, it is appropriate for the Lee Nuclear Station to be maintained as a potential resource option at this time to satisfy future projected load and energy requirements.

9. Duke's anticipated project development costs include the costs of review by, and responses to, the Nuclear Regulatory Commission (NRC), purchases of land and rights-of-way, site preparations, and project planning and engineering.

10. Payments required to ensure the timely fabrication and delivery of long-lead procurement items such as Reactor Coolant Pumps, Containment Vessel, Reactor Pressure Vessel, Steam Generators, Control Rod Drive Mechanisms and Condenser Circulating Water Piping for the Lee Nuclear Station qualify as project development costs to the extent that those costs are (a) incurred prior to the issuance of a Certificate of Public Convenience and Necessity by the Public Service Commission of South Carolina and (b) ultimately determined by the Commission to have been reasonable and prudently incurred.

11. Duke's decision to incur the North Carolina-allocable portion of an amount not to exceed $160 million in Lee Nuclear Station project development costs for the period from January 1, 2008, to December 31, 2009, is reasonable and prudent, and is approved subject to the reporting requirements set forth herein. The total of $160 million reflects total development costs (capital and AFUDC).

12. It is appropriate for Duke, on a provisional basis, to begin accruing AFUDC on Lee Nuclear Station project development costs concurrent with the capitalization of said costs, subject to future determinations by the Commission as to the reasonableness and prudence of all project development costs associated with the Lee Nuclear Station, including AFUDC. The appropriateness of the accounting treatment employed by the Company relative to said AFUDC will also be subject to future Commission determination.

13. It is appropriate to require Duke to file and serve reports similar to the reports required by the Commission in the Order Issuing Declaratory Ruling entered in this docket on March 20, 2007, as more specifically described hereinafter.

14. Should Duke decide to cancel the Lee Nuclear Station prior to the issuance of a certificate, any approval granted by the Commission in this proceeding should not be considered to be approval to record any abandoned project development costs in a regulatory asset account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence supporting these findings of fact is contained in the verified Application, the testimony in this docket, and the statutes and rules governing the authority and jurisdiction of the Commission. These findings are informational, procedural, and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 THROUGH 8

The evidence for these findings of fact is found in the testimony of Duke witnesses Ruff, Hager, and Wright, the testimony of Public Staff witnesses Maness and Ellis, the testimony of the Groups' witness Bradford, and in the Commission's *Order Approving Integrated Resource Plans* in Docket No. E-100, Sub 109, of which the Commission takes judicial notice pursuant to G.S. 62-65(b).

By Order entered July 9, 2007, in Docket No. E-100, Sub 109, which approved Duke's 2006 integrated resource plan, the Commission found Duke's peak and energy forecasts to be reasonable for planning purposes. These forecasts indicate ten-year average annual growth rates of 1.7% in Duke's summer peak and 1.6% in Duke's energy sales. This equates to an annual growth rate of 326 MW. The validity of the 2007 load forecasts submitted by Duke and Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., in their 2007 integrated resource plans has been set for hearing to begin on July 1, 2008. Duke witness Hager's testimony provided the load forecasts from the 2007 Plan.

Because of load growth, retirements of older generating units, and the expiration of purchased power contracts, witness Hager explained that Duke's 2007 Plan shows the need for 7,000 additional MW by 2018 and 10,280 MW by 2026. She further testified that the quantitative analyses in Duke's 2007 Plan suggest that a combination of additional base load, intermediate and peaking generation facilities, renewable resources, EE, and DSM is required over the next 20 years to meet customer demand reliably and cost effectively. Under both the Reference Case and the Carbon Case in Duke's 2007 Plan, the selected portfolio included 1,117 MW of nuclear capacity, with the optimal timing varying from 2016 to 2023.

Duke witness Hager also testified about the current uncertainties that were considered in the 2007 Plan, including the effects of environmental regulations on the cost of electricity and therefore the demand for it, whether and what type of carbon legislation might be passed, whether utilities will be able to secure sufficient renewable resources, whether DSM and EE will deliver the anticipated capacity and energy savings reliably, and whether worldwide demand for building materials will continue to cause price increases and lengthened delivery times. She stated that the environment for planning the Company's system has never been more dynamic and that, as a result, the Company believes that prudent planning for customer needs requires a plan that is robust under many possible future scenarios and maintains a number of options to respond to many potential outcomes relating to the major planning uncertainties. She concluded that, given the uncertainties posed by future economic, environmental, regulatory and operating circumstances, continuing to develop new nuclear generation as a resource option in the 2018 time frame is prudent because the 2007 Plan demonstrates that the Lee Nuclear Station has significant value for customers under multiple scenarios. She therefore asserted that the Company's decision to incur continued development costs for the Lee Nuclear Station is reasonable and requested that the Commission approve the Company's application.

The Public Staff witnesses testified that, based upon current load forecasts, the present uncertainty surrounding the amount and performance of renewable energy, EE, and DSM resources, and the present uncertainty with respect to carbon legislation in the future, Duke's general decision as of this date to incur project development costs appears to be reasonable and prudent so that the proposed Lee Nuclear Station can be maintained as a potential resource option to satisfy future projected load and energy requirements. The Public Staff witnesses did not challenge Duke's load forecasts for purposes of this proceeding.

In addition, the Public Staff witnesses testified that, on the advice of counsel, they believed that the phrases "reasonable and prudent" in paragraph (c) of G.S. 62-110.7 and "reasonable and prudently incurred" in paragraph (d) of that same statute refer to the determination of the "reasonableness or prudence of specific project activities or recoverability of specific items of cost," as that phrase is used in paragraph (b) of the statute. Paragraph (b) explicitly excludes such a determination from a proceeding pursuant to G.S. 62-110.7, which is limited to a determination as to whether the general decision made at or before the time of the application to incur proposed project development costs is reasonable and prudent and does not include a determination as to the reasonableness and prudence of any subsequent specific activities or expenditures. The witnesses further emphasized that this proceeding does not involve a determination as to whether a base load plant would be needed nor any findings as to whether the Lee Nuclear Station should be built.

In their Brief, the Groups contended that Duke presented no competent evidence at the hearing in support of its claim that the costs that it expected to spend at the Lee Nuclear Station were either reasonable or prudent. This implied position of "trust us to make a multibillion dollar commitment in your best interest" simply does not meet Duke's burden. The Groups maintained that much of the testimony by Duke's witnesses was no more than bald assertions that the Lee Nuclear Station would meet expected baseload demand and benefit ratepayers, and that there was no factual basis behind any of these assertions, no analysis of the future of the nuclear industry, no presentation of how much the ratepayers would ultimately pay, or how the Lee Nuclear Station would affect the rates and bills of Duke's customers. The Commission cannot determine that the costs associated with the open-ended "project development" activities proposed by Duke are reasonable and prudent without investigating how the proposed costs relate to the costs associated with the total project. As a result, the Commission is required to make a determination that, in light of the costs of the plants, it is a reasonable investment by the ratepayers to start in on the process.

The Groups' witness Bradford testified that the Commission should have the Company's current best cost estimate for the Lee Nuclear Station in the context of its rate impacts and a comparison of the alternatives before making a decision in this proceeding. He further testified that the Commission should confine the scope of its review as narrowly as possible under the statute and that Duke should be required to use a competitive procurement process at periodic intervals to screen possible power supply resources. Finally, he testified that the Commission should limit the total cost of the project that it would consider to be a prudent commitment at this time, and, because EE programs are available at a lower cost than the proposed nuclear station, the Commission should require a showing that programs are in place to capture all cost-effective EE before it accepts as prudent any decision to build a nuclear unit.

In rebuttal, Duke witness Wright testified that this hearing is not about whether a specific preconstruction cost is prudent and recoverable in rates, that Duke has not yet decided to build the Lee Nuclear Station, and appropriate filings related to a decision to build and the related plant construction costs would come at a later date if and when such a decision is made. He emphasized that, if the Company decided to proceed with construction of the proposed Lee Nuclear Station, there would be a future hearing related to approval of the need for the plant. As part of this proceeding, the Company would have to provide construction cost estimates, a proposed construction schedule, and annual updates. In addition, ongoing monitoring, review, and reports are provided or by Commission rule.

Duke witness Wright further testified that, in a rapidly growing state like North Carolina, neither the Company nor the Commission has the luxury of waiting to see what happens or of continuing to delay making decisions on resource options. This proceeding is about whether the nuclear option should be kept open as a potential base load generation resource to serve this state at the time that current studies indicate such generation would be needed. Given planned retirements of older generating facilities and the current uncertainty with respect to the future of carbon taxes and other limitations, witness Wright stated that approving the Company's request and keeping nuclear generation on the table as an option for the 2018 time frame is prudent and that it would be imprudent not to continue to preserve nuclear as an option at this time.

At the outset, the Commission notes that it appears that all parties would agree that the current planning environment is characterized by numerous uncertainties that affect a broad spectrum of issues and potential options for meeting customer demand. Even if Duke's current load forecast is overstated, Duke clearly will continue to have significant load growth unless DSM and EE can successfully be ramped up very dramatically. It is too soon to know how effective such programs will be. Similarly, it is not yet clear how much and what types of renewable facilities will be available or whether such facilities can be used to meet base load. Finally, there is substantial uncertainty as to whether carbon legislation will be enacted and, if it is, how stringent it will be and how much it will cost. All of these factors and the others discussed by the witnesses in this proceeding militate in favor of keeping all options open at this time.

As noted in both the Public Staff's testimony and in Duke's rebuttal testimony, this proceeding does not address the issue of whether Duke needs a base load generating facility within the relevant time frame, a determination as to whether or not the Lee Nuclear Station should in fact be built, or any findings with respect to the reasonableness and prudence of specific activities or expenditures. Most of the recommendations made by the Groups appear to be based on the assumption that this proceeding entails greater assurances than it actually will provide. In addition, many of the concerns expressed by the Groups are more appropriately addressed in a certificate proceeding or its equivalent or in other proceedings in which the prudence and reasonableness of specific activities and costs will be evaluated and determined. For example, with respect to the Groups' recommendation that the Commission require a showing that programs are in place to capture all cost-effective EE before it accepts as prudent any decision to build a nuclear unit, G.S. 62-110.1(e) specifically provides for such a finding to be made in a certificate proceeding.

Based upon the foregoing, the Commission concludes that, given current load forecasts, the uncertainty surrounding the amount and performance of renewable energy, EE, and DSM resources, the present uncertainty with respect to carbon legislation in the future, and the other uncertainties discussed herein, the Lee Nuclear Station should be maintained at this time as a potential resource option to satisfy future projected load and energy requirements.

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

The evidence for these findings of fact is found in the direct testimony of Duke witness Jamil, who adopted the prefiled testimony of Henry B. Barron, the rebuttal testimony of Mr. Jamil, the testimony of Public Staff witnesses Maness and Ellis, and the testimony of the Groups' witness Bradford.

Duke witness Jamil testified that Duke's anticipated project development costs include the costs of review by, and responses to, the NRC, purchases of land and rights-of-way, site preparations, and project planning and engineering, the latter of which Duke asserts includes limited initial payments on long-lead material and equipment items. He further testified that, based upon information available to Duke at this time, Duke anticipates spending up to $160 million for project development work for the period January 1, 2008, through December 31, 2009. Duke witness Ruff testified that Duke believes the decision to incur total project development costs of up to $160 million for the period January 1, 2008, through December 31, 2009, is prudent and reasonable.

Duke witness Jamil testified that Duke believes that payments required to ensure the timely fabrication and delivery of long-lead procurement items such as Reactor Coolant Pumps, Containment Vessel, Reactor Pressure Vessel, Steam Generators, Control Rod Drive Mechanisms, and Condenser Circulating Water Piping constitute "project development costs" because such payments are required "pre-construction" obligations to ensure that the Lee Nuclear Station can remain an option for commercial operation in the 2018 timeframe. The Company does not currently know with precision which items would require long-lead procurement decisions, how far in advance those decisions would have to be made, or the amount or timing of advance obligations that would be required to secure and maintain a place in the fabrication queue for those items. However, Mr. Jamil testified that Duke's cost estimate and development schedule anticipate that the Reactor Coolant Pumps, Containment Vessel, Reactor Pressure Vessel, Steam Generators, Control Rod Drive Mechanisms, Condenser Circulating Water Piping, and numerous other power plant components will need to be ordered and certain advance payments made well before on-site construction activity actually commences on the project. Witness Jamil testified that the Company needs the flexibility to potentially lock in a place in line to guarantee that it can procure certain long-lead items due to the global movement to construct nuclear and other power plants. Witness Jamil testified that such long lead-payments to secure a place in line would eventually be applied to the cost of the long-lead component.

The Public Staff witnesses testified that they believe that both a time limit and a total dollar cap should be imposed and, that at a minimum, the Commission should impose the January 1, 2008, through December 31, 2009, time limitation and the maximum $160 million expenditure limitation proposed by Duke in its application. The witnesses stated, however, that they preferred that the Commission limit the time period to January 1, 2008, through March 31, 2009, and correspondingly limit the dollar amount to a maximum of the North Carolina allocable share of $90 million, including any AFUDC accrued by Duke during the approved 2008/2009 timeframe on the amounts spent both before, and on or after, January 1, 2008. They further testified that such limitations are not unreasonable given the dynamic status of construction cost estimates and the current uncertainty with respect to renewable energy, EE, and DSM resources and potential carbon legislation. Additionally, they noted that a March 31, 2009 cut-off date would correspond with the evaluation of Duke's next integrated resource plan, which is due to be filed on September 1, 2008, pursuant to Commission Rule R8-60, and to which parties have 150 days to file in response.

The Groups' witness Bradford testified that the initial payments on long-lead material and equipment items should not be considered to be project development costs. Instead, he asserted, project development costs should be limited to the essential costs of preparing to go forward with the project, which would not include the very large costs of getting in line for particular long-lead time items. He further stated that this is particularly the case in this proceeding because the Commission does not have any real sense of the magnitude of these costs, the contractual commitments that would go with them, nor how easy it would be to sell them to someone else if the decision were made ultimately to not go forward with the project.

On rebuttal, Duke witness Jamil testified in opposition to the Public Staff's proposed shorter project development period and the correspondingly lower maximum amount of $90 million. He stated that the Company has significant development work planned over the next two years, and that Commission approval now to incur development costs through 2009 would be more efficient and would reduce the likelihood of possible delay or interruptions. He further testified that Duke currently is evaluating updated, detailed cost information received from Westinghouse/Shaw and that, in addition to the Company's internal evaluation, an independent assessment of the cost information is planned. Duke expects this work to review the cost information to take several months.

On cross-examination by the Public Staff, witness Jamil stated that, up until Duke files an application for a certificate, it can file another application similar to the pending application; that he provided to the Public Staff the $90 million estimate for the shorter time period; and that $90 million is the amount Duke expects to spend from January 1, 2008, through March 31, 2009. He further stated that the shorter time period and the $90 million did not include any initial payments on long-lead material and equipment items.

In its Brief, CUCA stated that it does not oppose the Commission allowing Duke to continue to explore the possibility of constructing the Lee Nuclear Station. CUCA maintained that, in the context of its overall annual revenues and expenses, the amount of expense proposed by Duke as a cap in this case, for the period January 1, 2008, through December 31, 2009, does not appear to be extravagant or excessive. CUCA concluded that, based on the number of future unknown factors, allowing Duke to proceed with its exploration of the nuclear option appears to be, from a consumer perspective, relatively cheap insurance to keep the nuclear option available for the 2018-2020 timeframe.

The Commission notes the concern by the Groups that payments on long-lead material and equipment items should not be considered to be project development costs. These types of items are not specifically listed in G.S. 62-110.7(a) in the definition of project development costs. The Commission must look to the nature of what the particular costs in question in this proceeding constitute in order to resolve this issue. In this case, while the costs are indeed initial payments toward material and equipment, they are also, as witness Bradford testified, costs of getting in line for particular long-lead time items. If such expenses are not incurred by Duke during the time of project development, the result may be that such long-lead time items may not be available to Duke in the timeframe needed to build the facility. In essence, these costs appear to the Commission to be required not as material and equipment costs, but more as time-holders to assure that the timeframe option that Duke is considering for construction of a nuclear facility remains viable. As such, the Commission finds that such payments meet the definition of development costs.

In addition, the Commission further concludes that, while there is potential benefit to accepting the Public Staff's proposal to limit approval to a maximum of $90 million and a time limit through March 31, 2009, Duke's argument that such limitations might cause possible project delays or interruptions also has significant merit. In order to assure that the nuclear option remains available to Duke in the timeframe that it may be required, this Commission ultimately comes down on the side of the increased flexibility requested by Duke, and thus approves Duke's decision to incur project development costs of up to $160 million during the period from January 1, 2008, to December 31, 2009. The total of $160 million being approved by the Commission in this proceeding reflects total development costs (capital and AFUDC).

Finally, the Commission wishes to emphasize that approval of the $160 million limitation is a not-to-exceed amount or cap. No specific costs or activities are being approved, and all activities and expenditures will be subject to later determinations as to their reasonableness and prudence. This Order does not cover a decision to incur project development costs between January 1, 2008, and December 31, 2009, greater than the North Carolina allocable share of $160 million; nor is it a decision to incur any project development costs after December 31, 2009. Approval under G.S. 62-110.7 of a general decision to spend more than that amount or to incur project development costs after that period will require a further application by the Company and review by the Commission.

Furthermore, in making this decision, the Commission has carefully considered Duke's current cost estimates for the Lee Nuclear Station as well as recent publicly-available industry cost estimates for new nuclear generation. The Commission does not find such cost information to be an impediment to, or inconsistent with, approving Duke's decision to incur project development costs for the Lee Nuclear Station in order to maintain such plant as a potential resource option to satisfy future projected load and energy requirements.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Maness and Ellis and the rebuttal testimony of Duke witness Wiles.

The Public Staff witnesses testified that, under the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA), which has been adopted by the Commission – with certain conditions and exceptions – as its accounting rules for electric public utilities under its jurisdiction,[1] project development costs are typically recorded in FERC Account 183 – Preliminary Survey and Investigation Charges. The Public Staff observed that:

> This account is defined to include 'all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation.'

Alternatively, according to the Public Staff, if the cost defined as a project development cost by G.S. 62-110.7 is actually a cost that is more accurately described as a construction cost by the USOA, it may be recorded directly to FERC Account 107 – Construction Work in Progress (CWIP).

In its Proposed Order, the Public Staff further observed that:

> The account description of FERC Account 183 also states that 'If construction results, this account shall be credited and the appropriate utility plant account charged,' which would typically be FERC Account 107.

The Public Staff further stated that, therefore:

> . . . all project development costs, assuming they are directly associated with a nuclear facility that progresses from being a potential facility to being a facility actually under construction, will eventually be recorded in FERC Account 107, the account used by the utilities to accumulate CWIP.

Additionally, in its Proposed Order, the Public Staff stated that:

> [its] witnesses further testified that, if the plant under construction ultimately proceeds to commercial operation and if no regulatory disallowances or other write-offs occur, the costs that began their lives as project development costs will be transferred to FERC Account 101 – Electric Plant in Service, the account utilized to account for the plant costs that are typically included in the utility's rate base as plant in service. Thus, the witnesses concluded [that] specific project development activities and expenditures undertaken and made prior to the certification of a generation facility are subject to review as they pass through CWIP and into plant in service.

According to the Public Staff:

> Duke rebuttal witness Wile[s'] testimony explained Duke's accounting for nuclear generation project development costs and why Duke believed such costs

[1] See Commission Rule R8-27 Uniform System of Accounts.

for the Lee Nuclear Station are no longer attributable to FERC Account 183. He testified that, under the FERC USOA, it was appropriate to record the project development costs that are the subject of this application in Account 107 because, once management selected the site for the Lee Nuclear Station, Duke deemed construction of the project to have begun for accounting purposes. As a result, the incurred project development costs were moved to FERC Account 107.

In addition, witness Wile[s] argued that Duke's interpretation of what constitutes 'in progress of construction,' as that phrase is used in FERC Account 107, is consistent with the guidance in the Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 34 (Statement 34) regarding when interest costs should begin to be capitalized.

On cross-examination, witness Wile[s] agreed that the Company and the Public Staff essentially agreed that project development costs will initially be recorded, either in Account 183 or Account 107, will pass through Account 107 during the construction process, and will all end up in Account 101, assuming no write-offs or disallowances. He stated that there is judgment involved in determining when costs move between Account 183 and Account 107, specifically in how 'under construction' is interpreted. He agreed that Electric Plant Instruction 3(A)(20) lent itself to an interpretation that studies performed for plants not yet under construction would be recorded in Account 183. He also agreed that, under Commission Rule R8-27(a)(1), for North Carolina retail jurisdictional purposes, the Commission ultimately is in control of determining whether the Company's accounting for project development costs is correct, notwithstanding the USOA. Finally, he agreed that the provisions of the Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 71 (Statement 71), rather than Statement 34, control the accrual of AFUDC for regulated entities such as Duke.

Based upon the foregoing, the Public Staff recommended that the Commission conclude that:

> . . . the appropriate accounting and ratemaking treatment of project development costs, including the date at which AFUDC may begin to be accrued, will be determined by the Commission at the appropriate time.

In its Proposed Order, Duke commented as follows:

> Duke Energy Carolinas and the Public Staff concur that under the Federal Energy Regulatory Commission ('FERC') Uniform System of Accounts, which has been adopted by the Commission in its Rule R8-27, 'expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of utility projects under contemplation' are recorded in FERC Account 183. (Tr. Vol. 2, p. 29; p. 124). The account description of FERC Account 183 also states that '[i]f construction results, this account shall be

credited and the appropriate utility plant account charged,' which would typically be FERC Account 107. Public Staff witness panel Ellis and Maness testified that all project development costs, assuming they are directly associated with a nuclear facility that progresses from being a potential facility to being a facility actually under construction, will eventually be recorded in FERC Account 107, the account used by utilities to accumulate CWIP. (Tr. Vol. 2, p. 29).

James D. Wiles, Vice President of Franchised Electric & Gas Accounting for Duke Energy, testified that Duke Energy Carolinas is following the FERC guidance in accounting for the project development costs associated with the Lee Nuclear Station. (Tr. Vol. 2, p. 124-25). During the site selection process, the Company captured project development costs in FERC Account 183. (Tr. Vol. 2, p. 125). Mr. Wiles explained that once management selected the site for the Lee Nuclear Station, however, the Company deemed construction of the project to have begun for accounting purposes. (*Id.*). Therefore, costs specifically related to sites not selected were expensed, and the other costs incurred related to the Lee Nuclear Station for project development costs, as defined by the Statute, were moved to FERC Account 107. Therefore, the project development costs associated with the Lee Nuclear Station and the site selected are now recorded in FERC Account 107. (*Id.*). Mr. Wiles testified that Duke Energy Carolinas has consistently applied this accounting convention to each of the Company's other nuclear sites. (*Id.*).

Witness Wiles testified that FERC's Uniform System Of Accounts indicates that the project development costs as defined by N.C. Gen. Stat. §62-110.7 are included as construction costs. (Tr. Vol. 2, p. 125). Mr. Wiles also testified that Duke Energy Carolinas' interpretation of what constitutes ' . . . in process of construction' as that phrase is used in FERC Account 107, is consistent with the guidance in Statement of Financial Accounting Standards No. 34 - Capitalization of Interest Cost (SFAS No. 34), regarding when interest costs should begin to be capitalized. (Tr. Vol. 2, p. 125-26).

Witness Wiles noted that SFAS No. 34 indicates that '. . . [t]he term *activities* is to be constructed broadly. It encompasses more than physical construction; it includes all steps required to prepare the asset for its intended use. For example, it includes administrative and technical activities during the preconstruction stage.' (Tr. Vol. 2, p. 126). For the Company, all of the criteria for the capitalization of interest under SFAS No. 34, and the capitalization of allowance for funds used during construction ('AFUDC'), have been met once the site for the facility has been selected. (*Id.*). The Company's accounting is consistent with N.C. Gen. Stat. § 62-110.7 which states that 'project development costs' include '. . . allowance for funds used during construction associated with such costs.' (Tr. Vol. 2, p. 126-27).

In conclusion, Duke argued that (a) the Public Staff's testimony does not directly contradict witness Wiles' testimony; (b) because the Company has selected the site for the Lee

Nuclear Station, the project development costs that are the subject of this request are properly attributable to FERC Account 107; and, therefore, (c) Duke's accounting for the Lee Nuclear Station project development costs is reasonable and, as such, should be accepted by the Commission.

In its Brief, CUCA recommended that the Commission require Duke to record the expenditure of the additional sums sought by Duke in this instance in FERC Account 183. CUCA also requested:

> . . . that the Commission Order specifically note that its approval of the present Duke Application does not obligate or require the Commission ever to approve any cost recovery of these expenditures and does not commit or require the Commission to grant ultimate approval for construction of the Lee Nuclear Station.

The parties have argued at length in regard to the appropriate FERC Accounts to which the costs in question should be assigned. The core issue is: When is it appropriate for Duke to accrue or begin accruing a carrying charge or, stated alternatively, AFUDC, with respect to costs incurred relative to the Lee Nuclear Station? Based upon the evidence presented, including the testimony of the witnesses, the Commission concludes that the FERC USOA does not contain definite language that can be cited as unambiguous, authoritative support for purposes of resolving this issue, and no on-point FERC precedent appears to exist. On the other hand, G.S. 62-110.7(a) defines "project development costs," in pertinent part, to mean all capital costs associated with a potential out-of-state nuclear generating facility incurred **before issuance of a certificate by the host state**, including allowance for funds used during construction associated with such costs. Thus, the Commission concludes that G.S. 62-110.7 is controlling on the issue in question. Carrying charges, which are effectively synonymous with AFUDC, will be incurred by the Company concurrent with its incurrence and capitalization of other project development costs. Accordingly, in consideration of G.S. 62-110.7, it would be appropriate for Duke, on a provisional basis, to begin accruing AFUDC on Lee Nuclear Station project development costs concurrent with the capitalization of said costs, subject to future determinations by the Commission as to the reasonableness and prudence of all project development costs associated with the Lee Nuclear Station, including AFUDC. The Commission further finds and concludes that the accounting treatment employed by the Company regarding AFUDC will also be subject to future Commission determination as to appropriateness.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Maness and Ellis. The witnesses testified that Duke should be required to file and serve reports similar to the reports required by the Commission in the declaratory ruling order it issued in this docket on March 20, 2007. They further recommended that any Commission Order approving Duke's decision to incur project development costs provide that these reports are for informational purposes only and that they cannot be used as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and expenditures reported therein.

No party opposed these requested reporting requirements. The Commission concludes that they should be imposed as recommended. Furthermore, Duke should state in these reports whether there have been any revisions to the cost estimates for the Lee Nuclear Station and, if so, the revised cost estimate shall be provided, including AFUDC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Maness and Ellis. The witnesses testified that, if Duke decided to cancel the Lee Nuclear Station prior to the issuance of a certificate, any approval granted by the Commission in this proceeding should not be considered approval to record any abandoned project development costs in a regulatory asset account. They asserted that any such treatment requires an application to be filed by Duke with the Commission. The requirement of Commission Rule R8-27 for the Company to apply to the Commission for use of regulatory asset accounts should continue to apply in this case, because (1) any approval granted in this proceeding should not be understood as making it probable at this time that the recovery of any specific actual costs will be allowed and (2) it would be appropriate and beneficial for the Commission to begin to examine the circumstances of any abandonment as closely as possible in time to that abandonment, which would be facilitated by a requirement that a request for regulatory asset approval be filed.

No party opposed the Public Staff's recommendation and the Commission concludes that this recommendation should be adopted. The approval herein of Duke's decision to incur project development costs is not to be interpreted as making it probable at this time that the recovery of any specific actual costs would be allowed. Furthermore, Duke is required to file an application with the Commission in order to use a regulatory asset account for any abandoned project development costs.

CONCLUSIONS OF LAW

1. Duke has the burden of proof pursuant to G.S. 62-110.7 to show by a preponderance of the evidence that its decision to incur project development costs is reasonable and prudent.

2. Duke has met its burden by demonstrating that its decision, as of the date of the application, to incur project development costs so that the proposed Lee Nuclear Station can be maintained as a potential resource option to satisfy future projected load and energy requirements is reasonable and prudent.

3. The Commission's findings and conclusions with respect to the reasonableness and prudence of Duke's decision to incur proposed project development costs do not constitute approval to engage in any specific project development activities, nor to spend any specific amount. The determination of the reasonableness and prudence of specific project development activities and expenditures is reserved for later proceedings. Additionally, this approval of Duke's current decision generally to incur project development costs does not constitute a finding that additional base load capacity is needed within the relevant time frame; nor does it constitute a finding that the Lee Nuclear Station should in fact be built.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's decision to incur project development costs is approved, subject to the following: the maximum amount of project development costs to be incurred on and after January 1, 2008, that are deemed to be included in a reasonable and prudent decision to incur project development costs is the North Carolina allocable share of a total system amount of $160 million and the period of time for which the Company's decision to incur up to that amount is deemed reasonable and prudent is limited to the period of January 1, 2008, through December 31, 2009. The total of $160 million reflects total development costs (capital and AFUDC).

2. That approval of the $160 million cap is not approval of any particular activities being undertaken or any particular costs being incurred during that period of time. No specific activities or costs are being approved, and all activities and expenditures will be subject to later determinations as to their prudence and reasonableness.

3. That Duke is required to file the following: (a) on August 1, 2008, a report detailing its activities and expenditures in pursuit of project development for the Lee Nuclear Station from January 1, 2008, through June 30, 2008; (b) on February 1, 2009, a report detailing its activities and expenditures in pursuit of project development for the Lee Nuclear Station from July 1, 2008, through December 31, 2008; (c) on August 1, 2009, a report detailing its activities and expenditures in pursuit of project development for the Lee Nuclear Station from January 1, 2009, through June 30, 2009; and (d) on February 1, 2010, a report detailing its activities and expenditures in pursuit of project development for the Lee Nuclear Station from July 1, 2009, through December 31, 2009. Further, that Duke shall state in these reports whether there have been any revisions to the cost estimates for the Lee Nuclear Station and, if so, the revised cost estimates shall be provided, including AFUDC.

4. That the reports required by decretal paragraph number 3 shall be used for informational purposes only and shall not be used as support for an argument that the Commission has made any determination with respect to the reasonableness or prudence of the activities and expenditures reported therein.

5. That Duke is hereby placed on notice that the Commission's approval of the Company's decision to incur project development costs in this proceeding cannot be interpreted as making it probable at this time that the recovery of any specific actual costs will be allowed and that Duke is required to file an application with the Commission prior to the use of a regulatory asset account with respect to any abandoned project development costs.

6. That it is appropriate for Duke, on a provisional basis, to begin accruing AFUDC on Lee Nuclear Station project development costs concurrent with the capitalization of said costs, subject to future determinations by the Commission as to the reasonableness and prudence of all project development costs associated with the Lee Nuclear Station, including AFUDC. The appropriateness of the accounting treatment employed by the Company relative to said AFUDC shall also be subject to future Commission determination.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of June, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

je061108.01

DOCKET NO. E-7, SUB 819

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC	)	ORDER DENYING MOTION TO
for Approval of Decision to Incur Nuclear	)	RESCIND ORDER APPROVING
Generation Project Development Costs	)	DECISION TO INCUR PROJECT
	)	DEVELOPMENT COSTS

BEFORE: Chairman Edward S. Finley, Jr., Presiding; and Commissioners Robert V. Owens, Jr., Sam J. Ervin, IV, Lorinzo L. Joyner, Howard N. Lee, and William T. Culpepper, III

BY THE COMMISSION: On December 7, 2007, Duke Energy Carolinas, LLC (Duke or Company) filed an Application for Approval of Decision to Incur Continued Nuclear Generation Project Development Costs. By its application, Duke sought authority to incur additional project development costs of up to $160 million for the period January 1, 2008, through December 31, 2009, for the Company's proposed Lee Nuclear Station in Cherokee County, South Carolina. Duke filed this application pursuant to G.S. 62-60, G.S. 1-253, G.S. 62-2, G.S. 62-110.7, and prior Orders of the Commission entered in this docket. As to G.S. 62-110.7, Duke acknowledged that this statute did not become effective until January 1, 2008, but requested that the Commission deem its application to have been filed pursuant to that statute as of January 2, 2008, or provide advice as to whether the Company should refile its application at that time.

The Commission entered an Order Approving Decision to Incur Project Development Costs in this docket on June 11, 2008. By that Order, the Commission, in pertinent part, approved Duke's decision to incur project development costs, subject to the following: the maximum amount of project development costs to be incurred on and after January 1, 2008, that is deemed to be included in a reasonable and prudent decision to incur project development costs is the North Carolina allocable share of a total system amount of $160 million; and the period of time for which the Company's decision to incur up to that amount is deemed reasonable and prudent is limited to the period of January 1, 2008, through December 31, 2009. The total of $160 million reflects total development costs (capital and AFUDC). The Commission further held that approval of the $160 million cap is not approval of any particular activities being undertaken or any particular costs being incurred during that period of time. The Commission noted that no specific activities or costs were being approved, and that all activities and expenditures would be subject to later determinations as to their prudence and reasonableness. Duke was also placed on notice that the Commission's approval of the Company's decision to incur project development costs in this proceeding could not be interpreted as making it probable at this time that the recovery of any specific actual costs would be allowed, and Duke was required to file an application with the Commission prior to the use of a regulatory asset account with respect to any abandoned project development costs.

On July 25, 2008, multiple intervenors, who collectively call themselves the "Public Advocacy Groups" (the Groups)[1], filed a motion in this docket pursuant to G.S. 62-80 whereby the Commission has been requested to rescind the Order of June 11, 2008. On August 5, 2008, the Groups filed a supplement to their motion to rescind. The Groups assert that significant design and operational procedures for the Lee Nuclear Station, which relies on the Westinghouse AP1000 Rev. 16 design, are not now known and will not be known unless and until the proposed nuclear reactor design is both certified by the Nuclear Regulatory Commission (NRC) and accepted by Duke. Therefore, the Groups state that the costs of the nuclear reactor design remain unquantifiable and that the expenditure of any funds at this time by Duke is not "reasonable and prudent" as required by G.S. 62-110.7. The Groups assert that the risks of delays and cost overruns that stem from changes to the reactor design will increase significantly if construction proceeds without a certified design.

On July 28, 2008, the Commission entered an Order in this docket whereby the other parties to this proceeding were requested to file comments in response to the Groups' motion.

On August 18, 2008, Duke filed a response in opposition to the Groups' motion. Duke asserts that the Groups' motion is untimely; that it is barred by G.S. 62-90 and G.S. 62-80; and that it fails to raise any legitimate issue not previously considered by the Commission. According to Duke, the basis of the Groups' motion is purported new "evidence," which it attempts to argue establishes uncertainty as to the NRC design certification for the AP1000 technology selected for the proposed Lee Nuclear Station. What has happened at the NRC is simply part of the process described by Duke in support of its application. This Commission's Order approving Duke's application cited the uncertainties surrounding the current planning environment as support for its decision. As reflected in the Commission's Order, the purpose of Duke's application was to obtain the Commission's approval of its decision to incur preconstruction costs in connection with the proposed Lee Nuclear Station. As authorized by G.S. 62-110.7, this proceeding focuses on whether it is reasonable for the Company to take steps in preparation for potential construction of that facility in light of the information known at the time. The statutory provision explicitly contemplates a review of a proposed or planned facility at an early time in the planning process prior to the commencement of construction.

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[1] The "Public Advocacy Groups" include the following intervenors: N.C. Waste Awareness and Reduction Network, Public Citizen, the N.C. Public Interest Research Group, the Nuclear Information and Resource Service, Common Sense at the Nuclear Crossroads, Clean Water for N.C., and the Blue Ridge Environmental Defense League.

According to Duke, the uncertainties and challenges regarding the technical and NRC regulatory approval process for the Lee Nuclear Station on which the Groups mistakenly predicate their motion were not only expressly acknowledged by Duke in this proceeding before the Commission, but form the very basis of the Company's application to determine the prudence of its decision to incur preconstruction costs. The Commission considered this evidence, the Groups' testimony, and the record as a whole in issuing its Order. Approval of revisions to certified designs is just one part of the lengthy and complex approval process which must be completed in connection with the proposed Lee Nuclear Station. The fact that additional information is requested by the NRC from Westinghouse in the certification process and that a deadline may be changing in that process is no basis for amending or rescinding this Commission's approval of the decision by the Company to incur costs to keep the nuclear option open. The Groups' motion presents no legitimate basis for the relief it seeks and it should be denied.

The other parties to this proceeding (the Public Staff, the Attorney General, the Carolina Industrial Group for Fair Utility Rates III, and the Carolina Utility Customers Association, Inc.) did not file responses to the Groups' motion.

WHEREUPON, the Commission finds good cause to deny the motion to rescind the June 11, 2008 Order filed by the Groups. The Commission has carefully reviewed the record in this proceeding and finds no basis, pursuant to G.S. 62-80, to rescind, alter, or amend the Order Approving Decision to Incur Project Development Costs. Therefore, the June 11, 2008 Order is hereby affirmed for the reasons generally given by Duke in Section II of its August 18, 2008 response.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of August, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bb082508.01

DOCKET NO. E-7, SUB 856

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC, for Approval of a Solar Photovoltaic Distributed Generation Program and for Approval of the Proposed Method of Recovery of Associated Costs	)))))	ORDER GRANTING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY WITH CONDITIONS

HEARD: Thursday, October 23, 2008, at 9:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Robert V. Owens, Jr., Sam J. Ervin, IV, Howard N. Lee, and William T. Culpepper, III

APPEARANCES:

For Duke Energy Carolinas, LLC:

Lara S. Nichols, Associate General Counsel, and Brian L. Franklin, Senior Counsel, Duke Energy Corporation, Post Office Box 1244-PB05E, Charlotte, North Carolina 28201-1244

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

For Wal-Mart Stores East, LP, and Sam's East, Inc.:

Rick D. Chamberlain, Behrens, Taylor, Wheeler & Chamberlain, Six Northeast 63rd Street, Suite 400, Oklahoma City, Oklahoma 73105

For Southern Alliance for Clean Energy:

George S. Cavros, Attorney at Law, 120 East Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334

For North Carolina Sustainable Energy Association:

Kurt J. Olson, Staff Counsel, Post Office Box 6465, Raleigh, North Carolina 27628

For The Solar Alliance and The Vote Solar Initiative:

R. Sarah Compton, Attorney at Law, Post Office Box 12728, Raleigh, North Carolina 27605

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: On June 6, 2008, Duke Energy Carolinas, LLC (Duke), filed an application for a blanket Certificate of Public Convenience and Necessity (CPCN) authorizing construction over a two-year period of up to 20 megawatts (MW) direct current (DC) of solar photovoltaic (PV) generation and for approval of its proposed method of cost recovery. The facilities will be located within Duke's North Carolina service territory and will include both roof-mounted and ground-mounted facilities installed on the property of Duke's customers and on property owned by Duke. Duke will own all the facilities under the program, and the facilities will be interconnected directly to the power grid at the distribution or transmission level.

The scale of the program provides for multiple types of installations in multiple locations. Eighty to ninety percent (80-90%) of the proposed installed capacity will consist of large-scale installations such as ground-mounted facilities and rooftop installations on large commercial or industrial buildings, with individual facilities in this category ranging from 500 kilowatts (kW) to 3 MW. Up to 10% of the proposed installed capacity will consist of medium-scale rooftop facilities, with individual facilities in this category ranging in size from 15 to 500 kW. Small-scale facilities on residential rooftops, ranging from 1.5 to 5 kW in capacity, will comprise the remainder of the program and up to 10% of the total capacity.

On July 8, 2008, the Commission issued an Order setting the matter for hearing, directing Duke to give notice to its customers, and establishing discovery and other procedural deadlines.

Petitions to intervene were filed by the following parties and granted by order of the Commission: Carolina Utility Customers Association, Inc.; The Kroger Co.; Southern Alliance for Clean Energy; the North Carolina Sustainable Energy Association (NCSEA); Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively, Wal-Mart); The Vote Solar Initiative (Vote Solar); and The Solar Alliance. The Attorney General filed a notice of intervention on June 23, 2008, which is recognized pursuant to G.S. 62-20. Lastly, the intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On July 25, 2008, Duke filed the direct testimony and exhibits of Janice D. Hager, Jane L. McManeus, Owen A. Smith, and Ellen T. Ruff.

On October 8, 2008, NCSEA filed the testimony Rosalie R. Day.

On October 10, 2008, pursuant to orders allowing extensions of time, Solar Alliance filed the testimony of Carrie Cullen Hitt, Vote Solar filed the testimony and exhibits of Thomas J. Starrs, Wal-Mart filed the testimony of Ken Baker, and the Public Staff filed the testimony and exhibits of Elise Cox and James McLawhorn.

On October 20, 2008, Duke filed the revised direct testimony of Ellen T. Ruff, the rebuttal testimony of Jane L. McManeus, and the rebuttal testimony and exhibits of Owen A. Smith.

This matter came on for hearing as scheduled on October 23, 2008. Duke presented the testimony and exhibits of witnesses Ruff, Smith, Hager and McManeus; Wal-Mart presented the testimony of witness Baker; Vote Solar presented the testimony and exhibits of witness Starrs; the Solar Alliance presented the testimony of witness Hitt; NCSEA presented the testimony of witness Day; and the Public Staff presented the testimony and exhibits of witnesses Cox and McLawhorn.

Based upon the foregoing, the testimony and exhibits introduced into evidence at the hearing, and the Commission's record of this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. Duke is a public utility providing electric service to customers in its service area in North Carolina subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over this application. Pursuant to G.S. 62-110.1 and Commission Rule R8-61(b), a public utility must receive a CPCN prior to constructing electric generating facilities in North Carolina.

3. In its application, Duke requested authorization to install new solar PV electric generating facilities with a total capacity of approximately 20 MW (DC). These facilities will be dispersed throughout Duke's North Carolina service territory and will be installed as roof-mounted and ground-mounted facilities on the property of Duke's customers and on property owned by Duke. In its application, Duke estimated that the cost of the proposed facilities would be approximately $100 million. In its rebuttal testimony, Duke reduced the size of its proposed program to 10 MW (DC), with an estimated cost of $50 million.

4. In order to meet the solar set-aside requirements of the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS), G.S. 62-133.8(d), there is a need for Duke to acquire solar energy. Duke's proposed construction of 10 MW of solar PV generating facilities is an appropriate method for meeting a portion of this statutory requirement.

5. In addition to developing its program for construction of solar PV facilities on its own system, Duke also issued a request for proposals (RFP) which was open to bidders who could provide at least 2 MW of bundled renewable generation and renewable energy certificates (RECs). The RFP was not open to bidders with a capacity of less than 2 MW, to bidders offering RECs separately from the associated electric energy, or to providers of solar thermal energy.

6. The lowest solar bid submitted in response to Duke's RFP was from SunEdison. Duke has entered into a contract to purchase the energy and RECs offered by SunEdison.

7. Duke received numerous other solar bids in response to its RFP, many of which were priced lower per MWh than the estimated costs of Duke's program.

8. Duke, as a public utility, is required to follow certain tax normalization requirements with respect to the treatment of federal energy investment tax credits. The bidders responding to Duke's RFP are not public utilities and are not subject to these tax normalization requirements.

9. Duke employed an engineering firm, Black & Veatch, to analyze, in part, the bids submitted in response to its RFP. Duke had a reasonable opportunity to enter into contracts for solar energy and RECs from bidders in addition to SunEdison at a price lower than Duke's estimated costs for its program.

10. Duke anticipates that, in addition to simply providing solar energy to meet the REPS requirements, the program will provide certain additional benefits which it believes cannot be obtained through a purchase from a third party. These additional benefits include enabling Duke to develop competency as an owner of solar renewable assets; to leverage volume purchases; to build relationships with solar PV developers, manufacturers and installers; to gain experience with the installation and operation of various types of solar distributed generation (DG) facilities; and to evaluate the impact of such facilities on its electric system. In addition, Duke expects that the program will help it to understand the types of DG facilities desired by customers, promote the commercialization of solar facilities in North Carolina, and fill knowledge gaps so as to enable successful, widespread deployment of solar PV technologies. Moreover, Duke notes that, if it owns solar generating facilities, it will not be entirely dependent on purchases from outside entities to meet the solar requirements contained in the REPS.

11. Duke should not be required to make reports to the Commission on the information it gathers from the solar PV facilities installed in connection with the program or to gather comparable information from solar PV facilities owned by others.

12. The costs of Duke's program, like the costs of any purchase of bundled solar energy, include avoided costs that are quantifiable. Under G.S. 62-133.8(h), avoided costs are not incremental costs and may not be recovered through the REPS and REPS Experience Modification Factor (EMF) riders. Moreover, the avoided costs of Duke's program may not be recovered through the fuel and fuel-related costs rider under G.S. 62-133.2.

13. G.S. 62-133.8(h) states that incremental compliance costs may be recovered through the REPS and REPS EMF riders. G.S. 62-133.8(h)(1) provides that compliance costs must be "reasonable and prudent" in order to be recovered as incremental costs. To the extent that the costs of the program exceed the cost for which Duke could have reasonably purchased solar energy and RECs from a third party, Duke has not met its burden of proving that these costs are reasonable and prudent and, therefore, eligible for recovery as incremental costs through the REPS and REPS EMF riders.

14. The estimated costs provided by Duke include the costs associated with the broader benefits of the program. They also include the costs associated with the public utility tax normalization requirements. G.S. 62-133.8(h)(1) provides that incremental costs include, among other things, "costs incurred by an electric power supplier to ... [c]omply with the requirements of subsections (b), (c), (d), (e), and (f)" of G.S. 62-133.8. The costs associated with the broader benefits of Duke's program and with Duke's tax normalization obligations will not be incurred to

comply with the requirements of G.S. 62-133.8(b)-(f). Consequently, these costs may not be recovered through the REPS and REPS EMF riders, except to the extent that they may be shown in a future proceeding to constitute research and development expenses recoverable pursuant to G.S. 62-133.8(h)(1)(b).

15. The reasonable and appropriate costs to comply with G.S. 62-133.8(b)-(f) to be recovered by Duke through the REPS and REPS EMF riders shall not exceed the price offered in the third-lowest bid submitted in response to Duke's solar RFP, less avoided costs.

16. The public convenience and necessity require the implementation of Duke's proposed program, subject to the following conditions: (1) that the facilities constructed to implement the program shall not exceed a total of 10 MW in capacity, and (2) that no more than the price offered in the third-lowest bid submitted in response to Duke's solar RFP, less avoided costs, may be recovered through the REPS and REPS EMF riders pursuant to G.S. 62-133.8(h)(1)(a).

17. Duke has estimated the construction cost of the program at $50 million. The Commission approves this estimate and finds, pursuant to G.S. 62-110.1(e), that construction of these facilities will be consistent with the Commission's plan for expansion of electric generating capacity; provided, however, that the Commission's approval of the estimate does not amount to approval of recovery of costs in excess of the level provided herein.

18. Duke should not be required to allow the host of a solar facility to retain a portion of the RECs produced by the facility or to retain a portion of the energy produced.

19. Duke should not be required to provide a standard offer for the purchase of solar RECs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 1-2

These findings of fact are essentially informational, jurisdictional and procedural in nature and are not controversial.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 3-4

The evidence supporting these findings of fact appears in Duke's application and in the testimony of Duke witnesses Ruff and Smith and Public Staff witnesses Cox and McLawhorn.

In August 2007, the General Assembly enacted Session Law 2007-397 (Senate Bill 3), which established a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in this State. G.S. 62-133.8. The REPS requires all North Carolina electric suppliers to include specified percentages of renewable generation in their generation portfolio. Subsection (d) of G.S. 62-133.8 provides that specified percentages "of the total electric power in kilowatt hours sold to retail electric customers in the State, or an equivalent amount of energy, shall be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities ...." The required percentages of solar energy are 0.02% for 2010-11, 0.07% for 2012-14, 0.14% for 2015-17, and 0.20% for 2018 and subsequent years. Under G.S. 62-133.8(h), a utility may recover the incremental cost of compliance with the REPS from customers through an annual rider. The amount of the rider for any given customer account is subject to an annual limit (the "per-account cap"), which is set by the statute at different levels for residential, commercial and industrial customers. If a utility's incremental costs of compliance for a given year are equal to the combined total of the per-account caps for all its North Carolina retail customers (the "utility-wide ceiling"), the utility is conclusively deemed to be in compliance with the REPS for that year, notwithstanding its failure to achieve the percentages of renewable generation provided for in the statute. No incremental costs of REPS compliance in excess of the utility-wide ceiling may be recovered from ratepayers.

Duke witness Ruff testified that Duke's proposed solar PV facilities are "renewable energy facilities" within the meaning of the REPS statute and will enable Duke to partially fulfill its obligations under the REPS and the solar set-aside.

Duke witness Smith, in his direct testimony, provided a detailed description of the solar PV facilities that Duke proposes to install. He stated that the facilities are expected to have a total combined capacity of approximately 20 MW (DC), which will be converted to about 16 to 17 MW alternating current (AC). The facilities will be installed on both customer- and Company-owned property in Duke's North Carolina service area. They will consist of large- or medium-scale ground-mounted facilities and rooftop installations on commercial, industrial and residential buildings. The facilities will be installed over a two-year period following approval by the Commission, and their total cost is estimated to be $100 million. Witness Smith described Duke's proposed tariff for the program, and he explained that a blanket CPCN for the program is needed because the precise location of the facilities cannot be specified at this time and because waiting to determine such locations before filing multiple applications for individual CPCNs would unduly delay the program and increase its costs.

Public Staff witnesses Cox and McLawhorn testified that Duke's proposed program appears to be needed to meet the starting date for the solar set-aside requirements, but that it should be limited to 10 MW rather than the 20 MW proposed by Duke. In support of their recommendation to reduce the size of the project, witnesses Cox and McLawhorn noted that Duke has already entered into a contract to purchase solar energy from SunEdison. In combination with the SunEdison project, Duke's program will produce much more solar energy than is needed for compliance with the solar set-aside from 2010 through 2014. The witnesses stated that, while solar generation should be encouraged, it should not be pursued at the expense of other, less costly renewable resources because this could result in Duke's prematurely reaching the utility-wide ceiling established by G.S. 62-133.8(h). If Duke generates an excessive amount of costly solar energy, the total amount of renewable energy it can purchase or generate within the limits of its utility-wide cost cap will be reduced. This may result in a need to operate Duke's fossil-fired generating plants more often, possibly leading to increased emissions. Witnesses Cox and McLawhorn further testified that, if Duke generates substantially more solar energy in 2010-14 than is needed for compliance with the solar set-aside, it could bank the RECs associated with the excess solar generation and use them in later years. However, in their view, this type of large-scale banking of solar RECs is not a desirable practice because (1) it raises issues of intergenerational equity and (2) there is a substantial possibility that the costs of solar power may decrease in future years. In that event, Duke will be spending money unwisely by accumulating large numbers of solar RECs in advance of the need for them.

Duke witness Smith stated in his rebuttal testimony that Duke had decided to reduce the size of the program from 20 MW to 10 MW and that this would reduce the cost of the program to $50 million. He testified that the proposed tariff for the program had been revised accordingly and was attached to his testimony as Smith Rebuttal Exhibit 1.

The Commission agrees with Duke and the Public Staff that the solar facilities Duke proposes to construct, not to exceed 10 MW in capacity, are needed for compliance with G.S. 62-133.8(d).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 5-7

The evidence supporting these findings of fact appears in the testimony of Duke witness Smith and Public Staff witnesses Cox and McLawhorn.

Public Staff witnesses Cox and McLawhorn testified that they had reviewed the process used by Duke to solicit bids for renewable energy. Their review indicated that Duke issued an RFP for renewable energy in 2007 and received numerous solar bids in response. Duke's RFP was restricted to bidders offering bundled RECs and energy from facilities at least 2 MW in capacity. In addition, solar thermal projects, which do not produce any electricity, but do produce RECs that can be used to satisfy the REPS solar set-aside, were ineligible to submit bids.

On cross-examination, Duke witness Smith confirmed that the lowest solar bid in response to Duke's RFP was submitted by SunEdison, with which Duke has entered into a contract for solar energy and RECs. He stated that Public Staff Smith Confidential Cross-Examination Exhibit 1 is a listing, initially prepared by Duke, of the solar bids received in response to the RFP and the amounts of the bids, adjusted by Duke to be comparable with each other and with Duke's own proposal to facilitate easier comparison.

On these matters there is no disagreement among the parties. The Commission finds the facts to be as set forth above.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 8

The evidence supporting this finding of fact appears in the testimony of Duke witness McManeus.

Duke witness McManeus testified that, as a public utility, Duke is required to follow certain tax normalization requirements with respect to the treatment of the federal energy investment tax credit. Non-utilities, such as the bidders responding to Duke's RFP, are not subject to these tax normalization requirements. She further testified that the estimated cost of Duke's program is higher than the costs associated with a number of the bids received in response to the RFP due, in part, to these tax normalization requirements.

None of the parties disagreed with witness McManeus's testimony as to the cost of Duke's program or as to what the program would cost if Duke were not subject to tax normalization requirements. The Commission finds the facts to be in accordance with the testimony of Duke witness McManeus.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 9

The evidence supporting this finding of fact appears in the testimony of Public Staff witnesses Cox and McLawhorn and Duke witness Smith.

Public Staff witnesses Cox and McLawhorn testified that, in their review of Duke's RFP process, they ascertained that Duke had employed the firm of Black & Veatch to perform an analysis of the bids.

On cross-examination, Duke witness Smith testified that Public Staff Smith Confidential Cross-Examination Exhibit 2 was a summary of the Black & Veatch analysis, while Public Staff Smith Confidential Cross-Examination Exhibit 3 was a memorandum prepared by Black & Veatch setting out the results of the analysis in detail.

Although there may be some differences of opinion among the parties concerning the qualifications and reliability of some of the bidders responding to Duke's RFP, the Commission finds that Duke had a reasonable opportunity to enter into contracts for solar energy and RECs from bidders in addition to SunEdison at a price lower than Duke's estimated costs for its proposed program.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 10-11

The evidence supporting these findings of fact appears in the testimony of Duke witnesses Ruff and Smith, Solar Alliance witness Hitt, and Public Staff witnesses Cox and McLawhorn.

Duke witness Ruff testified that, in addition to providing solar energy to meet customer demand and to satisfy Duke's REPS obligations, the program will have a variety of other benefits. It will help promote the development of solar generation resources in North Carolina. The distributed nature of the generation of electricity under the program will enable Duke to develop competency as an owner of solar renewable assets; leverage volume purchases; build relationships with solar PV developers, manufacturers and installers; and gain experience with the installation and operation of multiple types of solar distributed generation (DG) facilities. Additionally, if Duke owns some of the generating facilities that it uses to meet the solar requirements of the REPS, it will not be dependent solely on power purchases to meet these requirements.

Duke witness Smith testified that the Program will facilitate Duke's evaluation of the impact of significant DG on Duke's electric system. In addition, it will allow Duke to explore the nature of solar DG offerings desired by customers; fill knowledge gaps to enable successful, wide-scale deployment of solar PV DG technologies; and promote the commercialization of the solar market in North Carolina through utility ownership. It will promote energy security, attract investment and create jobs in the solar industry, and drive down the cost of solar PV installations through standardizing inspection requirements and leveraging volume purchases.

Solar Alliance witness Hitt testified that she was in agreement with Duke that the program will enable Duke to learn more about solar PV. She supported Duke's proposal to collect information about the economic and physical impacts of its planned solar PV installations. She recommended that Duke be required to collect comparable information from a sampling of installations that it does not own and to make all of this information available to the public through the Commission.

Public Staff witnesses Cox and McLawhorn expressed agreement with Duke's witnesses that the Company, through its proposed program, seeks to obtain benefits that go beyond the simple acquisition of solar energy and RECs for REPS compliance purposes.

The Commission is not persuaded that Duke should be required to make arrangements with other owners of solar PV facilities to collect data comparable to the data it gathers with respect to its own facilities. This could potentially be a useful undertaking, however, and Duke is encouraged to collect such data if it chooses to do so. The Commission notes that the data gathered by Duke will be subject to discovery in future proceedings, particularly integrated resource planning proceedings; consequently, there is no need to require Duke to submit the data formally to the Commission in periodic reports. Duke should refrain from designating this information as confidential, except for any specific data items as to which secrecy is truly essential.

Aside from the issues raised by witness Hitt and addressed above, the parties are in agreement concerning the broader benefits, above and beyond the acquisition of solar energy, that Duke seeks to obtain by constructing its own solar generating facilities. The Commission finds the facts to be in accordance with the testimony of the parties.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 12

The evidence supporting this finding of fact appears in the testimony of Duke witness McManeus, NCSEA witness Day, and Public Staff witnesses Cox and McLawhorn.

In her direct testimony, Duke witness McManeus stated that Duke proposed to recover all of the costs of the program, except for avoided costs, through the REPS rider. The costs to be recovered through the REPS rider include not only operation and maintenance costs, but also capital costs, which will be calculated on a levelized basis using a fixed charge rate applied to the investment and reduced by avoided cost.

NCSEA witness Day testified that avoided capacity and energy costs should be subtracted from the incremental costs to be recovered through the REPS and REPS EMF riders.

Public Staff witnesses Cox and McLawhorn testified that Duke's original plan, as disclosed during discovery, was to deduct only avoided capacity costs from the total levelized costs of the program and to recover all the remaining costs (including avoided energy costs) through the annual REPS and REPS EMF riders. However, Duke subsequently changed its position and agreed to deduct all avoided costs from the costs to be recovered in the REPS rider. According to witnesses Cox and McLawhorn, Duke should not recover any avoided costs through either the REPS rider or the fuel and fuel-related costs rider; these costs should be recovered only through base rates.

In her rebuttal testimony and on cross-examination, Duke witness McManeus agreed that neither avoided energy costs nor avoided capacity costs should be recovered through the REPS and

REPS EMF riders. She further agreed that, given the language of G.S. 62-133.2(a1), these costs could not be recovered through the fuel adjustment rider either, but instead had to be recovered through base rates. She expressed concern, however, that the language of G.S. 62-133.2(a1) places utilities generating renewable energy through their own facilities at an unwarranted disadvantage in comparison with utilities that purchase renewable energy from third parties and are able to use the fuel adjustment rider for recovery of avoided costs.

As a result of the change in Duke's position, there is no longer any disagreement among the parties on this issue. The Commission concludes that, under G.S. 62-133.8(h)(1), neither avoided energy costs nor avoided capacity costs are included in the "incremental costs" that can be recovered through the REPS and REPS EMF riders; that, under G.S. 62-133.2(a1)(6), the avoided energy and capacity costs of "all purchases of power from renewable energy facilities and new renewable energy facilities pursuant to G.S. 62-133.8" can be recovered through the fuel and fuel-related costs rider; and that G.S. 62-133.2 does not authorize a utility to recover through the fuel and fuel-related costs rider the avoided costs associated with renewable energy that it generates on its own system.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 13-15

The evidence supporting these findings of fact appears in the testimony of Duke witnesses Ruff, Smith and McManeus, NCSEA witness Day, and Public Staff witnesses Cox and McLawhorn.

Duke witness Ruff testified that, as a result of constructing its own solar facilities, Duke will not be dependent solely on power purchases from third parties to meet the requirements of G.S. 62-133.8(d) and that it will be more in control of the facilities used to meet those requirements than if it had relied on another entity to construct them.

Duke witness Smith testified that it is inappropriate to compare the estimated cost of the program with the bids received in response to Duke's RFP because of the broader benefits that will be provided by the program, but that cannot be obtained through a purchase of solar power from a third party. He stated that, prior to filing its application in this docket, Duke considered whether it would be reasonable to divide the costs of the program between different recovery mechanisms based upon the multiple benefits of the program; however, Duke decided not to pursue this approach because all generation produced by the program will serve to meet the REPS requirements. On cross-examination, witness Smith indicated that any proposal to replace Duke's program with a purchase of power from one of the RFP bidders (in addition to the SunEdison purchase Duke has already agreed to) would require Duke to have full confidence that the RFP bidder's project would come to fruition, and Duke is not comfortable with making such an assumption.

Duke witness McManeus testified that she disagreed with the Public Staff's proposal to limit the amount of program costs recoverable through the REPS and REPS EMF riders. While the Public Staff's witnesses opined that it was the distributed nature of the program that resulted in costs higher than certain of the solar bids Duke received, in her judgment the impact of the federal tax normalization requirements was the more significant driver of this difference. She testified that the goals of the program were different from, and more varied than, the goals that can be achieved through a simple purchase of power. Moreover, Duke would not have undertaken the program had the REPS legislation not been enacted, and all of the electricity generated by the program will be used for REPS compliance. On cross-examination, witness McManeus stated that it was not possible to break down the cost of the program into components representing the underlying cost of solar energy, the additional costs associated with the program's broader benefits, and the additional costs attributable to tax normalization. On cross-examination relating to Public Staff McManeus Confidential Cross-Examination Exhibit 1, she acknowledged that, if Duke chooses to generate solar energy through the program instead of purchasing it at a lower cost from a third party, it will reach the utility-wide ceiling established by G.S. 62-133.8(h) more quickly. If this occurs, then Duke will not be able to obtain as much renewable energy within the limits of the ceiling as it otherwise could; consequently, it will have to generate additional energy from its non-renewable facilities, possibly resulting in increased emissions.

NCSEA witness Day testified that Duke's program is too expensive and that the costs of the program will consume an excessive portion of Duke's utility-wide ceiling. She stated that Duke should seek conventional power plant financing for the program, and that the only costs of the program that should be recovered through the REPS and REPS EMF riders (aside from research costs) are the operations, leasing and maintenance costs of the solar PV facilities, less avoided costs.

Public Staff witnesses Cox and McLawhorn testified that Duke's program is very expensive, as can be seen by comparing the bids received in response to the RFP with the estimated cost of the program. A major reason for the high cost of the program is that it is designed not only to obtain solar energy for REPS compliance, but also to gain broader benefits, such as expertise in dealing with a wide range of solar technologies, information about what Duke's customers desire with regard to solar energy, and increased familiarity with DG. In discovery, the Public Staff requested Duke to break down the capital costs of the program between actual solar generation costs and the costs associated with the program's broader goals, but Duke responded that it could not do so. Witnesses Cox and McLawhorn stated that only the actual cost of solar energy (minus avoided costs) should be recovered through the REPS and REPS EMF riders. In their judgment, while any quantification of the actual cost of solar energy would necessarily be somewhat subjective, the bid submitted by the third-place bidder, as stated on Public Staff Smith Confidential Cross-Examination Exhibit 1, is an appropriate quantification under the specific facts of this case. The remaining costs of the program, to the extent that they meet the requirements of G.S. 62-133.8(h)(1)(b), may be sought to be recovered as research costs under the statute.

On cross-examination, witness McLawhorn stated that, although the Public Staff's proposed limit on cost recovery through the REPS and REPS EMF riders was equal to the amount of the third-place bid, he and witness Cox were not contending that Duke necessarily should have agreed to purchase power from that bidder or that the costs in excess of this amount were necessarily imprudent; they were simply adopting the figure as an estimate of, or proxy for, the actual cost of solar energy.

On this very complex issue, the parties are sharply in disagreement. Duke has requested the Commission to affirm that it will be allowed to recover its costs associated with the program through the REPS and REPS EMF riders. In considering this request, the Commission will begin its analysis by reviewing the relevant statutory provisions. Under G.S. 62-133.8(h)(4), incremental costs may be recovered through the REPS and REPS EMF riders. The term incremental costs is defined in G.S. 62-133.8(h)(1), which contains three paragraphs, (a) through (c), that identify three different categories of incremental costs. Paragraph (c) has no bearing on this case, and paragraph (b) will be addressed in a later section of this order. Of critical importance is paragraph (a), which provides that incremental costs include costs incurred to "[c]omply with the requirements of subsections (b), (c), (d), (e), and (f) of this subsection [the REPS percentage requirements] that are in excess of the electric power supplier's avoided costs." Equally important is the introductory clause of G.S. 62-133.8(h)(1), which makes it clear that only "reasonable and prudent costs" qualify as incremental costs. Thus, the Commission must deal with the question of whether the costs of the program are reasonable and prudent costs incurred for the purpose of complying with the REPS.

It is clear from the evidence presented in this case that at least some portion of the costs of Duke's program will, in fact, be incurred to acquire solar energy for compliance with the REPS solar set-aside. It is also clear that at least some portion of the costs will be incurred for the purpose of achieving the program's previously-stated broader goals. Finally, it is clear that a portion of the program costs will be incurred as a result of the federal tax normalization requirements applicable to public utilities.

Duke contends that the costs of the program should be viewed as unitary and indivisible; all of the costs should be viewed as being incurred to promote all of the program's purposes, and all should be recoverable through the REPS rider. Duke points out that there is no clear or simple method of attributing some of the program costs to one purpose and some to another. All of the funds spent on the program will be necessary for the program's completion; all of the energy generated by the program will be used for REPS compliance; and the program would never have been proposed if the REPS legislation had not been enacted.

The Commission is concerned, however, that allowing full recovery of the program's costs, as proposed by Duke, may lead to results inconsistent with the public interest and that it may also be inconsistent with the General Assembly's intent.

In the first place, if Duke is allowed to recover all the costs of the program through the REPS and REPS EMF riders, it may reach the utility-wide incremental cost ceiling prematurely, setting a precedent for other utilities in the State. Other utilities will be encouraged to undertake costly projects that are designed not only to comply with the REPS, but also to promote other goals, knowing that the entire costs of the project can be recovered through the REPS and REPS EMF riders. As Duke witness McManeus acknowledged on cross-examination, if a utility generates renewable energy at a higher cost when it could instead have purchased equivalent energy from a third party at a lower cost and it subsequently reaches the utility-wide ceiling, the result is that it will not be able to acquire as much renewable energy prior to reaching the ceiling as it could otherwise have acquired. Since the utility must meet its customer demand at all times, it must make up the shortfall in renewable generation by running its conventional plants for more hours, very likely resulting in increased emissions. In this way, the intent of G.S. 62-133.8 – to reduce emissions and protect the environment – will be thwarted.

Moreover, if Duke is allowed to recover all its program costs through the REPS and REPS EMF riders, this will not only have an adverse environmental effect, it will also be inconsistent with the goal of minimizing utility expenses and keeping rates down. Once the precedent has been set in this case, Duke and other utilities will be encouraged to undertake costly renewable generation projects that promote a variety of purposes in preference to less expensive projects designed solely for REPS compliance or purchases of renewable energy from third parties. They will know that, as long as a project produces some renewable energy, its entire cost (aside from avoided costs) can be recovered without any need for a rate case. The Commission believes that it is in the public interest for utilities to minimize the cost of REPS compliance and that the REPS and REPS EMF riders be restricted to costs that are truly intended for REPS compliance.

The Commission has steadfastly held that "least cost" considerations require the utility to test the market and to refrain from building generation if the required energy or capacity can be purchased at a lower cost and other considerations do not justify the construction of utility-owned generation. This issue was addressed explicitly in Duke's recent application for a CPCN to construct the Buck and Dan River natural gas-fired combined cycle facilities. Order Issuing Certificates of Public Convenience and Necessity, Docket No. E-7, Subs 791 and 832 (June 5, 2008). Analogously, the Commission's affiliate transaction rules impose a lower of cost or market rule on purchases by the utility. The rule should be no different in the case of renewable generation. While Senate Bill 3 allows a utility to meet its REPS requirement using its own generation, it also requires the utility to "implement demand-side management and energy efficiency measures and use supply side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of its customers." G.S. 62 133.9(b) (emphasis added). To allow Duke to recover any additional incremental costs through base rates would allow Duke effectively to recover more from its ratepayers for building its own solar generation that it could have paid to purchase such power and RECs in the market without adequate justification for that result.

Finally, it is the Commission's belief that when the General Assembly enacted G.S. 62-133.8, as well as other statutes providing for rate riders, the legislative intent was that these riders should be limited strictly to the purposes for which they were originally designed and that these statutory provisions should not be stretched to encompass other purposes. The General Assembly did not intend that riders be used to collect the entire costs of projects designed only partially to implement the goals of the rider.

The Commission, therefore, concludes that it is inappropriate to treat the costs of Duke's program as indivisible, with all costs being attributed to all the purposes of the program. Instead, it is necessary to attribute a portion of the costs to REPS compliance and a portion to other purposes (the broader program purposes outlined by Duke and compliance with tax normalization requirements). Only the costs attributed to REPS compliance may be recovered through the REPS rider pursuant to G.S. 62-133.8(h)(1)(a).

The evidence in this case shows that Duke had the opportunity to purchase solar energy from more than one bidder at a lower cost to its ratepayers. Instead, Duke is proposing to generate an equivalent amount of solar energy on its own system at a higher cost per MWh and to recover that amount, less avoided costs, through the REPS rider. Duke asserts that the broader benefits it hopes to gain from the program are sufficient to justify recovery of the program's costs through the

REPS rider. However, Duke has described these benefits only in vague conceptual terms; it has not explained why it could not obtain a greater understanding of the effects of DG on its system in other ways at a much lower cost (or why the same benefits are not available through power purchases), and it has made no attempt to quantify the value of the broader benefits.

Duke asserts, through the testimony of witness McManeus, that its federal tax normalization obligations provide a valid justification for the high costs of the program. The Commission disagrees. If the federal tax code treats self-generation of solar energy by a public utility less favorably than the purchase of solar energy from a third party, then prudence points in the direction of <u>not</u> self-generating, but instead purchasing the needed solar energy.

Duke asserts that it needs to be in control of its sources of generation, and that, if it constructs its own solar facilities, the risk of default will be lower than if it buys power from a facility built by a third party. However, Duke has presented no evidence that the lower-cost bidders lack the engineering or management skills to operate a solar generating facility efficiently, or that their financial condition is such as to pose a risk of default.

During the hearing, Duke appeared to take the position that a solar generating facility is comparable (with respect to the risk of default) to a nuclear plant, which can be brought to a complete shutdown in the event of a mechanical malfunction that creates a potentially unsafe condition and, consequently, requires extraordinary management and engineering skills or to a fossil plant which, similarly, may have to be reduced to a low output or shut down altogether in case of a problem with the boiler or emission controls. In fact, however, a solar PV facility, even a very large one, is quite different from a fossil or nuclear plant. It consists of an array of PV panels; even if one panel malfunctions, the others can continue to operate. Certainly, an entire solar facility may be rendered inoperable by a natural disaster or other catastrophic event, but Duke presented no evidence that it could protect its solar generating facilities against such eventualities more effectively than a third party could.

The Commission is not persuaded by Duke's argument that purchases from a third party are unreliable and would place Duke at risk of non-compliance with its REPS obligation. G.S. 62-133.8(d) provides that

> the Commission shall develop a procedure to determine if an electric power supplier is in compliance with the [solar set-aside] if a new solar electric facility or new metered solar thermal energy facility fails to meet the terms of its contract with the electric power supplier.

In its February 29, 2008 Order Adopting Final Rules, the Commission, in declining to include explicit language addressing this issue in its formal rules, implemented that statutory provision by stating

> The procedure for determining compliance adopted in the rules is through the review of an electric power supplier's REPS compliance report. An electric power supplier may petition the Commission to modify or delay the provisions of G.S. 62-133.7(d) and Rule R8-67(c)(5).

Thus, Duke is not without recourse if it has made a substantial, good faith effort to comply with the solar set-aside and, through no fault of its own, fails to meet the REPS requirement.

Given the very large difference between the costs of Duke's program and the costs at which power can be purchased from bidders who responded to Duke's solar RFP, Duke has failed to persuade the Commission that the costs of the program are all reasonable and prudent costs of REPS compliance. As previously noted, this does not mean that these costs must be disallowed or that Duke cannot carry its burden of demonstrating their prudence in a future case. It does mean, however, that the costs in excess of the limit established herein do not qualify as incremental costs within the meaning of G.S. 62-133.8(h)(1)(a).

Thus, with respect to the specific amount of costs to be attributed to REPS compliance, the Commission agrees with the Public Staff's witnesses that the effective price per MWh submitted by the third-place bidder in response to Duke's solar RFP is an appropriate amount at which to cap the level of compliance costs that are recoverable through the REPS and REPS EMF riders. As witnesses Cox and McLawhorn acknowledged, any specific amount is necessarily somewhat subjective given the circumstances of this case; but the Commission notes that this amount is approximately the amount at which Duke could have purchased power in response to its RFP, and it represents an amount significantly less than Duke's total costs.

It is not necessary for the Commission to go further and determine what portion of the remaining cost is attributable to tax normalization and what portion is attributable to the other purposes of the program.

Accordingly, the Commission finds that no more than the amount set forth above constitutes "reasonable and prudent costs incurred by an electric power supplier to ... [c]omply with the requirements" of the REPS within the meaning of G.S. 62-133.8(h)(1)(a), and no more than this amount may be recovered through the REPS and REPS EMF riders pursuant to paragraph (h)(1)(a).

It is important to emphasize that the Commission has given no consideration to disallowing any of the costs of Duke's program for imprudence. Except in very unusual circumstances, it would be inappropriate to disallow costs in a CPCN proceeding. Public Staff witness McLawhorn made it clear on cross-examination that the Public Staff did not propose that the Commission disallow any costs in this proceeding.

As the Commission has previously emphasized, the decision on this issue does not mean that the remaining costs of the program are being disallowed. If Duke is able to demonstrate in a future case that some or all of these costs have been incurred prudently to "[f]und research that encourages the development of renewable energy, energy efficiency, or improved air quality," then it can recover those costs through the REPS and REPS EMF riders pursuant to paragraph (h)(1)(b) of G.S. 62-133.8, subject to the $1,000,000 per year limitation set out in that paragraph.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 16

The evidence in support of this finding of fact is found in the testimony of Duke witnesses Smith and NCSEA witness Day.

NCSEA witness Rosalie Day testified that the term "private" investment in the preamble of Senate Bill 3 and in G.S. 62-3(a)(10) is meant to encourage non-utility investment in renewable generation and to exclude investment by investor-owned utilities.

Duke witness Smith disagreed, contrasting private investment with government funding. He explained that, because Duke is owned by its investors, its investment in the program also constitutes private investment in renewable energy within the meaning of G.S. 62-2(a)(10).

The Commission is not persuaded by the arguments put forth by NCSEA witness Day. The term "private investment" is not defined in Senate Bill 3. According to its common definition, "private" means "not established and maintained under public funds" The Random House Dictionary (1980). Furthermore, Senate Bill 3 clearly allows for REPS compliance through the generation of energy from utility-owned new renewable energy facilities. G.S. 62-133.8(b). As a result, it would be incongruous for this Commission to interpret the policy statements contained in G.S. 62-3(a)(10) to exclude utility investment in renewable energy.

The Commission's findings with respect to the need for Duke's proposed program, the appropriate size of the program, and the regulatory treatment of the costs of the program lead to the conclusion that the Certificate of Convenience and Necessity requested by Duke should be granted, but only on the condition that the total capacity of the program be limited to 10 MW and that the costs of the program to be recovered through the REPS and REPS EMF riders pursuant to G.S. 62-133.8(h)(1)(a) be limited as stated herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 17

The evidence supporting this finding of fact appears in the testimony of Duke witnesses Smith and Hager and Wal-Mart witness Baker.

Duke witness Smith stated in his rebuttal testimony that the estimated cost of the solar generating facilities to be constructed in connection with Duke's proposed program is \$50 million. He stated that, if Duke's cost estimate is lower or higher than what is actually achieved, any variance would have been reflected in the cost recovery mechanism under Duke's proposal.

Duke witness Hager testified that the program conforms to, and is an important and necessary part of, Duke's integrated resource plan for meeting customer capacity and energy needs.

Wal-Mart witness Baker testified that Duke's filing does not contain enough information to explain how Duke proposes to acquire solar panels at \$5,000 per kW and that the Commission should consider capping the costs of the program.

Although various parties disagreed with Duke's proposals for recovery of the costs of the program, no party took issue with witness Smith's testimony that the total capital costs of the program are currently estimated to be \$50 million. Neither did any party disagree with the testimony of witness Hager that the program is consistent with Duke's integrated resource plan. The Commission therefore finds the facts to be in accordance with these witnesses' testimony.

Recovery of the program's costs shall be limited, not as proposed by Wal-Mart, but as set forth herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 18

The evidence supporting this finding of fact appears in the testimony of Duke witness Smith and Wal-Mart witness Baker.

Wal-Mart witness Baker testified that Duke should be required to allow the host of a solar PV facility to retain a portion of RECs generated by the facility as compensation and that Duke should be required to allow the host the option to take some portion of the electricity generated by the facility.

Duke witness Smith testified that Duke's inclination is to offer cash as compensation for siting the solar PV facility on a customer's roof, but that Duke would like the flexibility to structure the lease agreement in a manner that would be prudent for fulfilling the program. He further stated that cash compensation for the use of the premises can effectively result in the same outcome for the host with much less complexity than compensation by means of retaining RECs or retaining some of the electricity produced. Duke would prefer the flexibility to finalize such decisions related to the lease agreement after its market research studies have concluded.

Based on the foregoing, the Commission concludes that it is inappropriate to require Duke to allow the host of the solar facilities to retain a portion of the RECs or to retain a portion of the energy generated, although compensation in the manner described by Wal-Mart witness Baker represents an option that is available to Duke. Duke should be allowed some flexibility in structuring the lease agreements to appropriately compensate the lessee.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 19

The evidence in support of this finding of fact is found in the testimony of Duke witness Smith, NCSEA witness Day, Vote Solar Initiative witness Starrs, and Solar Alliance witness Hitt.

Solar Alliance witness Hitt and Vote Solar witness Starrs both advocated the establishment of a mandatory standard REC purchase offer. Witness Starrs testified that requiring Duke to provide a long-term standard offer for solar RECs at a price equal to the cost of the program to the Company will potentially lower costs to customers. Witness Hitt echoed this sentiment. NCSEA witness Day advocates that "a certain amount" of solar market share should be reserved for customer-generators, which essentially would require utilities to purchase RECs from such customers.

Duke witness Smith testified that NCSEA's, the Solar Alliance's, and Vote Solar's apparent position is that Duke should be required to purchase RECs from any solar customer-generator at a price that is the higher of Duke's cost to implement the program or the amount needed for the customer-generator to earn an internal rate of return of 9% - 12% on its investment. Witness Smith contended that witnesses Starrs' and Hitt's supposition that a "must take" obligation at this price would result in lower costs to customers is untenable, and the overall parameters for the REC purchase model are unacceptable. For example, witness Smith testified that if too few customers acted on the incentive provided by the REC purchase model, and Duke had relied on it for compliance, the Company would not be able to comply with the REPS requirements. Alternatively, if a large number of customers acted on this incentive and Duke had no way to limit customer participation, it could exceed its REPS cost caps. Witness Smith also testified that Duke already is developing a standard REC offer which it would make available to customer-generators on an as needed basis for RECs for general and solar set-aside compliance based upon current market prices. Although Duke has not finalized the interval for updating pricing of the offer, witness Smith testified that a reasonable approach that it is considering is one where pricing would be updated quarterly. He testified that a key purpose of the standard offer is to create a streamlined approach to interacting with owners of small generators that produce relatively small quantities of RECs.

The Commission disagrees with witnesses Day, Starrs, and Hitt, and declines to require the Company to provide a standard REC offer for the purchase of solar RECs. Such a requirement would essentially mandate that utilities purchase RECs from customer-generators. The Commission has already ruled that Senate Bill 3 does not impose a mandatory REC purchase obligation on electric power suppliers. In its February 29, 2008 Order Adopting Final Rules in Docket No. E-100, Sub 113, the Commission stated that "the electric power suppliers are not ... obligated to purchase all RECs offered for purchase. The Commission is not persuaded that it is appropriate to impose such an obligation." The Commission is not persuaded that it is appropriate to do so now. Duke is only obligated to purchase enough solar energy to comply with the solar set-aside and is not obligated to purchase as much solar energy as customers are willing to provide.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's application for a Certificate of Public Convenience and Necessity to implement its proposed solar photovoltaic distributed generation program and to construct the associated generating facilities is hereby approved, subject to the conditions set forth herein below. This order shall constitute the certificate.

2. That the generating facilities constructed pursuant to this order shall not exceed a total of 10 MW (DC) in capacity.

3. That no more than the effective price per MWh submitted by the third-place bidder in response to Duke's solar RFP, as stated in Public Staff Smith Confidential Cross-Examination Exhibit 1, less Duke's avoided costs, may be recovered through the REPS and REPS EMF riders pursuant to G.S. 62-133.8(h)(1)(a). This restriction is without prejudice to Duke's right to apply for recovery of any remaining costs of the program pursuant to G.S. 62-133.8(h)(1)(b).

4. That the facilities certificated herein shall be constructed and operated in strict accordance with all applicable laws and regulations.

5. That the issuance of this Order does not constitute approval of the final costs associated herewith for ratemaking purposes and this Order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

6. That Duke's proposed tariff designated as Smith Rebuttal Exhibit 1, and entitled "Solar Photovoltaic Distributed Generation Program (NC)," is approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc123108.02

DOCKET NO. G-5, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	)))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Wednesday, October 22, 2008, at 10 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners Robert V. Owens, Jr., and William T. Culpepper, III

APPEARANCES:

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B. Craig Collins, SCANA Corporation, 1426 Main Street, Columbia, South Carolina 29218

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On May 30, 2008, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Public Service Company of North Carolina, Inc. (PSNC or Company), filed the direct testimony and exhibits of Candace A. Paton, Rates & Regulatory Manager, and Terina H. Cronin, General Manager, Gas Supply & Sales, in connection with the annual review of PSNC's gas costs for the twelve-month period ended March 31, 2008.

On June 4, 2008, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of Tuesday, August 12, 2008, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter. On June 30, 2008, PSNC filed a Motion for Admission to Practice and Statements of B. Craig Collins and PSNC, which was granted by the Commission on July 8, 2008.

On July 14, 2008, the Public Staff filed a Motion for Extension of Time to File Testimony and to Reschedule Hearing. On July 21, 2008, the Commission issued an Order

Granting Extension of Time and Rescheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Deadlines, and Requiring Public Notice. This Order rescheduled the hearing for October 22, 2008.

On October 7, 2008, the Public Staff filed the direct testimony of Thomas W. Farmer, Jr., Director, Economic Research Division; James G. Hoard, Assistant Director, Accounting Division; Julie G. Perry, Supervisor, Natural Gas Section, Accounting Division; and Jan A. Larsen, Public Utilities Engineer, Natural Gas Division.

On October 8, 2008, the Company filed its affidavits of publication.

On October 17, 2008, PSNC filed the rebuttal testimony of Candace A. Paton.

On October 22, 2008, the matter came on for hearing before the Commission. PSNC witnesses Cronin and Paton's prefiled testimony and exhibits were admitted into the record, as were the testimony and exhibits of Public Staff witnesses Farmer, Hoard, Perry, and Larsen. The PSNC and Public Staff witnesses testified at the hearing and answered questions from the Commission. No public witnesses appeared at the hearing.

Based on the testimony and exhibits received into evidence and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PSNC is a corporation duly organized and existing under the laws of the State of South Carolina, having its principal office and place of business in Gastonia, North Carolina. PSNC operates a natural gas pipeline system for the transportation, distribution, and sale of natural gas to approximately 461,000 winter-peak customers in the State of North Carolina.

2. PSNC is engaged in providing natural gas service to the public and is a public utility as defined in G.S. 62-3(23), subject to the jurisdiction of this Commission.

3. PSNC has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period for this proceeding is the twelve months ended March 31, 2008.

5. During the review period, PSNC incurred total gas costs of $408,011,504, which were composed of demand and storage charges of $69,642,033, commodity gas costs of $327,319,194, and other gas costs of $11,050,277.

6. In compliance with the Commission's order in Docket No. G-100, Sub 67, the Company credited 75% of the net compensation from secondary market transactions, which amounted to $7,978,874, to its All Customers Deferred Account.

7. PSNC has recorded all the necessary adjustments to the Uncollectible Gas Cost entries pursuant to the Commission's Order in Docket No. G-5, Sub 488.

8. The Company has properly accounted for its gas costs incurred during the review period.

9. It is appropriate to allow the requested waiver of Rule R1-17(k)(4)(c) as it applies to the June 2007 and June 2008 Company Use and Lost and Unaccounted For (CU&LUAF) true-ups by approving the use of the Company's proposed method for comparing actual CU&LUAF with actual CU&LUAF expenses.

10. The appropriate CU&LUAF adjustment to be recorded in the All Customers Deferred Account for the twelve months ended June 30, 2007 is a credit of ($828,735), which incorporates a ($765,679) CU&LUAF adjusting entry plus interest of ($63,056).

11. It is appropriate to modify the monthly commodity true-up, effective July 1, 2008, in such a manner that the annual CU&LUAF true-up will be eliminated.

12. It is appropriate that the Commission initiate a rulemaking proceeding to modify Rule R1-17(k) and the gas cost adjustment procedures set out in Rule R1-17(k) to modify the proposed CU&LUAF true-up procedures.

13. PSNC has adopted a gas supply policy that it refers to as a "best cost" supply strategy. This gas supply policy is based upon three primary criteria: supply security, operational flexibility, and the cost of gas.

14. PSNC has a portfolio of long-term and supplemental short-term supply agreements with a variety of suppliers, including gas producers, an interstate pipeline marketing company, and independent marketers.

15. At March 31, 2008, the Company had a debit balance of $2,800,634 in its Sales Customers Only Deferred Account and a credit balance of ($846,552) in its All Customers Deferred Account.

16. PSNC should begin providing a Hedging Status Report no more than five calendar days after the end of each month, based on market values at the end of each month. Additionally, a reconciliation of the Hedging Status Report to the Hedging Deferred Account Report should be provided monthly.

17. PSNC's hedging activities during the review period were reasonable and prudent.

18. As of March 31, 2008, the Company had a debit balance of $21,826,139 in its Hedging Deferred Account.

19. It is appropriate to transfer the $21,826,139 debit balance from the Hedging Deferred Account to the Sales Customers Only Deferred Account. Subsequent to the transfer, the Sales Customers Only Deferred Account would have a net debit balance of $24,626,773.

20. The gas costs incurred by PSNC during the review period were prudently incurred.

21. The Company should implement the temporary increments and decrements recommended by Public Staff witness Larsen as a result of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

These findings are essentially informational, procedural, or jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and the testimony and exhibits filed by the witnesses for PSNC and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Cronin and Paton and Public Staff witness Perry. The findings are based on G.S. 62-133.4 and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that PSNC submit to the Commission information and data for an historical twelve-month review period, including PSNC's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. In addition to such information, Commission Rule R1-17(k)(6)(c) requires that PSNC file weather normalization data, sales volume data, workpapers, and direct testimony and exhibits supporting the information filed.

Witness Cronin testified that Rule R1-17(k)(6) requires PSNC to submit to the Commission on or before June 1 of each year certain information accompanied by supporting workpapers based on the twelve-month period ending March 31. Witness Cronin indicated that the Company had filed the required information. Witness Paton also indicated that the Company had provided to the Commission and the Public Staff on a monthly basis the gas cost and deferred gas cost account information required by Commission Rule R1-17(k)(5)(c). Public Staff witness Perry stated that the Public Staff had reviewed the monthly deferred gas cost account reports. The Commission concludes that PSNC has complied with the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the twelve-month review period ended March 31, 2008.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 - 8

The evidence supporting these findings of fact is found in the testimony of PSNC witness Paton and Public Staff witness Perry.

PSNC witness Paton's exhibits reflect demand and storage costs of $69,642,033, commodity costs of $327,319,194, and other gas costs of $11,050,277, for a total of $408,011,504. Public Staff witness Perry agreed that total gas costs for the review period ended March 31, 2008 were $408,011,504. Witness Perry further testified that PSNC properly accounted for its gas costs during the review period.

Public Staff witness Perry stated that the Company earned $10,638,499 of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $7,978,874 ($10,638,499 x 75%) was credited to the All Customers Deferred Account for the benefit of ratepayers.

Public Staff witness Perry testified that in PSNC's prior annual gas cost review, Docket No. G-5, Sub 488, the Commission ordered PSNC to record a correcting entry in its Sales Customers Only Deferred Account related to the uncollectible gas cost entries recorded during that review period. She further testified that the Order also stated that the entries would be subject to review in the next annual review proceeding. Company witness Paton provided testimony explaining several uncollectible gas cost adjustments that PSNC recorded in the Sales Customers Only Deferred Account during the current review period that related to both the prior review period and the current review period. Witness Perry testified that the Public Staff had reviewed these entries and the supporting data and found the adjusting entries to be correct.

Witness Perry stated that the Public Staff will continue to closely monitor and review the uncollectible gas cost entries recorded in the deferred account due to the number of corrections that have been noted during both review periods as well as in deferred accounts filed subsequent to the review period.

The Commission finds that PSNC has recorded all the necessary adjustments to the Uncollectible Gas Cost entries required by the Commission's Order in Docket No. G-5, Sub 488, and that these corrected entries are accurate. The Commission further concludes that PSNC has properly accounted for its gas costs during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 - 12

The evidence for these findings of fact is found in the testimony of PSNC witness Paton and Public Staff witness Hoard.

PSNC witness Paton testified that the Company recorded its annual CU&LUAF true-up in June 2007 pursuant to Rule R1-17(k)(4)(c). She also stated that, upon further analysis, the Company realized that the existing true-up process did not result in the recovery of the actual gas costs incurred as provided in G.S. 62-133.4. Witness Paton testified that the rule as written does not allow the Company to recover 100% of its CU&LUAF gas costs because the true-up is based on the presumed level of cost recovery and not on the actual level of cost the Company recovers from its customers.

Public Staff witness Hoard stated that, through the testimony of Company witness Paton, the Company had requested a waiver of the application of Rule R1-17(k)(4)(c) relating to the June 2007 CU&LUAF true-up, which is subject to review in this proceeding. He stated that the Company had also requested a waiver of the Rule as it applies to the June 2008 CU&LUAF true-up, which will be subject to review by the Commission in the Company's next annual review proceeding. Witness Hoard further testified that the Company's reason for requesting these waivers was that the current CU&LUAF true-up method specified in the Rule is inaccurate and does not allow the Company to recover 100% of its prudently incurred gas costs as intended by Rule R1-17(k). Public Staff witness Hoard testified that, during the review period, the Company recorded a $1,315,580 credit to its All Customers Deferred Account related to the June 2007 CU&LUAF true-up. In her pre-filed testimony, Company witness Paton proposed a revised computation, on Paton Schedule 13 of her exhibit, which produced a $1,947,338 credit for the CU&LUAF true-up. She computed the true-up amount by comparing actual CU&LUAF collections to the related expenses. She computed the collections by multiplying the volumes for each month by the applicable CU&LUAF rate elements, while she computed the expenses by multiplying the actual CU&LUAF volumes by the weighted benchmark for the year.

Witness Hoard testified that the June 2008 CU&LUAF true-up, as shown in the Company's June Deferred Account Report and revised in its July 2008 report, was calculated using the same method as the June 2007 true-up on the collections side, but refines the computation of the CU&LUAF expenses, as compared to the June 2007 true-up that is reflected in Paton Schedule 13. Witness Hoard stated that he believed that the method used to compute the June 2008 CU&LUAF, as revised in the July 2008 Deferred Account Report, results in the Company recovering 100% of its prudently incurred gas costs.

Witness Hoard recommended that the June 2007 CU&LUAF true-up be computed in the same manner that the Company used to compute its June 2008 true-up. He testified that the correct June 2007 true-up amount, using the June 2008 true-up methodology, was a credit to the All Customers Deferred Account of ($828,735), which incorporates a ($765,679) CU&LUAF adjusting entry plus interest of ($63,056).

The Commission agrees with the Public Staff and concludes that the Company's request for a waiver of Rule R1-17(k)(4)(c) should be allowed as it applies to the June 2007 and June 2008 CU&LUAF true-ups and that the appropriate CU&LUAF amount to be recorded in the All Customers Deferred Account for the twelve-month period ended June 30, 2007, is a credit of ($828,735), which incorporates a ($765,679) CU&LUAF adjusting entry plus interest of ($63,056).

Witness Hoard also proposed that the same method be used for purposes of computing the June 2008 CU&LUAF true-up, which will be subject to review in the Company's next annual review proceeding. For periods subsequent to June 2008, witness Hoard proposed that the commodity true-up be modified in such a manner that the annual CU&LUAF true-up would be eliminated. He proposed that the monthly commodity true-up entry to the deferred accounts be modified, effective July 1, 2008, such that the amount actually collected for gas supply costs from customers -- based on the volumes delivered to customers -- is compared to the actual amount of incurred gas supply costs. He further stated that the annual CU&LUAF true-up should be eliminated because, prospectively, the CU&LUAF true-up would be incorporated into the monthly commodity true-up. Consistent with Commission rulings that all customers, including transportation customers, should bear cost responsibility for CU&LUAF gas costs, witness Hoard recommended that the entry be apportioned between the Sales Customers Only and All Customers Deferred Accounts based on the relationship of sales to purchased dekatherms. Witness Hoard also stated that the Sales Customers Only Deferred Account should be apportioned a share of the commodity true-up based on the ratio of sales to purchased dekatherms and that the All Customers Deferred Account should be apportioned the residual portion of the entry, which will represent the CU&LUAF portion of the commodity true-up entry.

Witness Hoard further testified that, once the Commission issues an order accepting this new procedure for the commodity true-up, he recommended the Commission undertake a rulemaking proceeding to modify Rule R1-17(k) and the gas cost adjustment procedures so that they are consistent with the new procedures.

PSNC witness Paton testified in rebuttal testimony that the Company agreed with these recommendations.

The Commission agrees with the Public Staff's recommendations and further concludes that, effective July 1, 2008, the monthly commodity true-up entry recorded in PSNC's deferred accounts should be modified to incorporate the CU&LUAF true-up. Further, the Commission concludes that it is appropriate to issue an order in a separate docket establishing a rulemaking proceeding to address the appropriate modifications of Rule R1-17(k) needed to correctly address the recovery of CU&LUAF volumes.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 - 20

The evidence for these findings of fact is found in the testimony of PSNC witness Cronin and Public Staff witnesses Farmer, Perry, and Larsen.

PSNC witness Cronin testified that approximately 47% of PSNC's market is comprised of deliveries to industrial or large commercial customers that either purchase gas from PSNC or transport gas on PSNC's system. According to witness Cronin, many of these customers have the capability to use a fuel other than gas and will use an alternate fuel when it is priced below natural gas. The remainder of the Company's sales is primarily made to residential and small commercial customers. Electricity is PSNC's primary competition in these market segments.

PSNC witness Cronin further testified that the most appropriate description of PSNC's historical gas supply policy would be a "best cost" supply strategy, which is currently based on three primary criteria: supply security, operational flexibility, and the cost of gas. Witness Cronin indicated that security of supply is the first and foremost criterion. She stated that, in order to maintain the necessary supply security for all of the Company's firm customers, PSNC has supply contracts with delivery guarantees and storage service contracts with delivery rights that provide total gas deliveries to PSNC and that facilitate the full utilization of PSNC's firm interstate pipeline transportation and storage capacity. The rationale for this practice is PSNC's commitment to serve its firm market.

PSNC witness Cronin stated that the Company has long-term supply agreements and supplemental short-term agreements with a variety of suppliers, including producers, an interstate pipeline marketing company, and independent marketers. She stated that PSNC has increased the security of its gas supplies by developing a diversified portfolio of long and short-term suppliers.

PSNC witness Cronin testified that maintaining the necessary operational flexibility in its gas supply portfolio is the second criterion. Flexibility is required because of daily changes in market requirements related to weather, industrial customers' operating schedules, and the ability of industrial customers to switch to alternate fuels. She noted that, while each of the supply agreements has a different purchase commitment and swing capability, the gas supply portfolio as a whole must be capable of dealing with the monthly, daily, and hourly changes in the Company's market requirements.

In regard to the third criterion, cost of gas, witness Cronin stated that PSNC is committed to acquiring the most cost-effective gas supply while maintaining the security and operational flexibility needed to serve the needs of its customers. She noted that storage and the Company's hedging program are also utilized to help manage price volatility to PSNC's sales customers.

PSNC witness Cronin testified that, although PSNC had not made any changes to its Hedging Program during the review period, PSNC continues to review and evaluate the results of its Hedging Program. She stated that in April 2008, PSNC implemented two changes to the Hedging Program. The first change involved placing a greater emphasis on the purchase of call-options, including limiting the cost of the call-options to no more than 10% of the underlying commodity price. The second change was to reduce the maximum number of future months to hedge from 18 to 12 months. She testified that this reduction complements limiting the purchase price of call-options to 10% of the underlying commodity price.

PSNC witness Cronin stated that the greatest challenges facing the Company today involve making decisions that will affect the Company and its customers in the future, such as decisions regarding long-term gas supply, capacity, and hedging in an environment of regulatory, legislative, and market uncertainty.

PSNC witness Cronin stated that the majority of PSNC's interstate pipeline capacity is obtained from Transcontinental Gas Pipe Line Corporation (Transco), the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to redeliver gas, as well as storage service agreements with Dominion Transmission, Incorporated (DTI); Columbia Gas Transmission Corporation; East Tennessee Natural Gas Company (ETNG); Dominion Cove Point LNG, LP; Saltville Gas Storage Company, LLC; and Pine Needle LNG Company, LLC. She noted that PSNC also has upstream firm transportation (FT) agreements with Texas Gas Transmission Corporation and Transco, both of which feed into DTI.

Witness Cronin testified that, although PSNC did not acquire any additional interstate pipeline capacity or storage during the review period, PSNC has executed transportation and service agreements for the following interstate transportation capacity and storage services to begin subsequent to the end of the review period: 10,000 dekatherms per day with ETNG for FT service beginning in April 2008; another 10,000 dekatherms per day with ETNG for FT service beginning in December 2008; and 20,000 dekatherms per day maximum withdrawal quantity (200,000 dekatherms storage capacity) with Saltville for firm storage service that began in April 2008.

Ms. Cronin further testified that, in regard to the gas supply contracts that support the Company's FT capacity, PSNC has developed a portfolio gas supply strategy that includes the execution of long-term supply contracts which support the Company's best-cost supply strategy. According to witness Cronin, PSNC had approximately 223,000 dekatherms per day under contracts with seven major producers, one interstate pipeline marketing company, and two independent marketers as of November 1, 2007, the beginning of the winter heating season for the period under review. She testified that the contracts all have provisions to ensure that the prices paid are market sensitive.

PSNC witness Cronin testified that the gas supply and capacity portfolio that the Company has developed provides it the flexibility to meet its market requirements in a secure and cost-effective manner.

In addition, PSNC witness Cronin testified to the following activities that PSNC has engaged in to lower gas costs while maintaining security of supply and delivery flexibility:

1. During the review period, PSNC renegotiated pricing terms associated with one of its long-term supply agreements to ensure that charges accurately reflect market conditions. PSNC also entered into an agreement for an annual term with two new suppliers to replace service that expired during the review period;

2. PSNC continually evaluated various firm transportation and storage capacity options to ensure that future peak day requirements will be met;

3. PSNC has maintained the flexibility available within its supply and capacity contracts to cost-effectively purchase and dispatch gas;

4. PSNC continued to pursue and capture opportunities for capacity release and other secondary market transactions;

5. PSNC actively participated in matters before the Federal Energy Regulatory Commission (FERC) which may impact PSNC's rates and services to its customers;

6. PSNC continued to work with its industrial customers to transport customer-owned gas. Transportation services on PSNC's system permit gas to remain competitive with alternative fuels and allow PSNC to maintain throughput;

7. PSNC routinely communicated directly with customers, suppliers, and other industry participants, and actively monitored the industry using a variety of sources including industry trade periodicals; and

8. PSNC had frequent internal discussions among members of its senior management and that of its parent concerning gas supply policy and major purchasing decisions.

Public Staff witness Larsen stated that he reviewed the Company witnesses' testimony and exhibits, PSNC's gas supply and transportation contracts, and the Company's responses to the Public Staff's data requests, including design day estimates, system load imbalances, forecasted gas supply needs, projected capacity additions and supply changes, and customer load profile changes. Public Staff witness Larsen testified that, based upon his investigation, he believed that PSNC's gas costs during the review period were prudently incurred.

PSNC witness Cronin was questioned by the Commission on the subject of natural gas commodity prices. She testified that most of PSNC's supply contracts are based on a monthly first-of-the-month market index price that renders the contracts in question market-sensitive. She further testified that most of PSNC's contracts establish the first-of-the-month price using a published index that is based on average NYMEX natural gas futures contract closing prices during the last week prior to closing.

Witness Cronin acknowledged that concerns have been expressed over the course of the last six to eight months that natural gas prices have been affected by non-fundamental considerations including, in some instances, manipulative conduct by some suppliers. She stated that she was "somewhat" aware of the Amaranth investigation that the FERC has conducted. She also testified, "There has been a lot of money from hedge funds...a lot of speculative money in the market that I think has had an impact on natural gas prices." She added, "I believe that may be part of the reason driving natural gas prices up."

Witness Cronin testified that storage is a part of the Company's portfolio approach to gas supply. She acknowledged that, during the summer Of 2008, PSNC filled its storage facilities at a time when gas prices were at an unprecedently high level and did not seem to reflect market fundamentals. She testified that the price of gas in storage was "probably in the high 8 to $9 range," and is higher than current futures prices.

The Commission understands the need for market-sensitive pricing. It further understands that the trading of financial derivatives on a regulated commodities market is a logical and appropriate place for both buyers and sellers to look for a price-discovery mechanism. The Commission also understands that PSNC cannot, by itself, dictate pricing mechanisms to the market and that it is the responsibility of federal regulatory authorities -- and not PSNC or the Commission -- to ensure the integrity of the commodities markets. It finally understands that PSNC must fill storage during the summer months in order to ensure an adequate supply of natural gas in the winter. However, the Commission believes that PSNC and other regulated local distribution companies should not invariably remain content with the existing mechanisms for pricing natural gas commodity volumes delivered to sales customers. Instead, the Commission expects PSNC to regularly examine existing natural gas market pricing mechanisms in order to identify a pricing mechanism that reasonably reflects the fundamentals of the physical market for natural gas. The Commission will evaluate PSNC's efforts to determine the efficacy of existing pricing mechanisms and the extent to which other pricing mechanisms are reasonably available to the Company and in the public interest in next year's annual review of PSNC's gas costs.

The Commission concludes that the gas costs incurred by PSNC during the test period ended March 31, 2008, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

Public Staff witness Perry testified that, based on her review of the gas costs in this proceeding, the appropriate deferred account balance as of March 31, 2008 for the Sales Customers Only Deferred Account is a debit of $2,800,634. Witness Perry also stated that, based on the recommendation of Public Staff witness Hoard, the adjusted balance in the All Customers Deferred Account as of March 31, 2008, is a credit of ($846,552).

Company witness Paton stated in her rebuttal testimony that PSNC agreed with Public Staff witness Perry's March 31, 2008 deferred account balances.

The Commission concludes that the appropriate balances in the Company's deferred accounts as of March 31, 2008 are a debit balance of $2,800,634 in its Sales Customers Only Deferred Account and a credit balance of ($846,552) in its All Customers Deferred Account.

Public Staff witness Perry further testified that, during the review period, the Company incurred net debits of $21,826,139 in its Hedging Deferred Account. Hedging activity recorded during the review period included $14,962,873 of costs associated with realized positions; $2,796,125 of interest expense accrued on the Hedging Deferred Account; $2,907,213 of payments for option premiums, $1,155,584 of payments for margin requirements; and $4,344 for brokerage fees. In regard to PSNC's hedging activities, Public Staff witness Farmer testified that he reviewed the Company witnesses' testimony and exhibits, data request responses, and related reports. He stated that PSNC's hedging activities were reasonable and prudent and that the ending net debit balance of $21,826,139 should be transferred to the Company's Sales Customers Only Deferred Account. Subsequent to the transfer, the Sales Customers Only Deferred Account would have a net debit balance of $24,626,773.

The Commission agrees with the Public Staff that PSNC's hedging activities during the review period were reasonable and prudent and that its hedging net debits incurred during the review period should be transferred to the Company's Sales Customers Only Deferred Account.

Public Staff witness Hoard proposed in his testimony that PSNC file with the Commission a Hedging Status Report shortly after the end of each month, based on market values at the end of the month. Because market values can change dramatically over time and therefore affect the status of the Hedging Program, witness Hoard proposed that this Report should be filed no more than five calendar days after the end of the month. Witness Hoard further testified that this Hedging Status Report would serve to answer several key questions such as: (1) how much money has the Company made or lost on its Hedging Program; (2) what is the target amount of hedging volumes for each month; (3) what percent of each month's target has been hedged; and (4) at what price has the Company established hedges for each month?

Witness Hoard also stated that, because the proposed Hedging Status Report is a market-based report and the Hedging Deferred Account Report is a cash-based report, the values reported on the two reports are likely to differ significantly. Therefore, he proposed that the Company include a reconciliation of the two reports in its regular monthly Hedging Deferred Account Report.

Witness Hoard testified that the Company agrees, in concept, to his proposed Hedging Status Report and agrees to provide the requested information, though the specific parameters for the provision of some of that information may need further fine-tuning.

The Commission further concludes that PSNC should begin providing a Hedging Status Report no more than five calendar days after the end of each month, based on market values at the end of each month. The Commission also concludes that PSNC should include a reconciliation of the Hedging Deferred Account Report and the Hedging Status Report.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and Public Staff witness Larsen.

Company witness Paton testified that the Company was proposing new temporary decrements applicable to the All Customers Deferred Account. She stated that, based solely on the per-books over-collection at the end of the review period, the Company would not recommend new temporary rate decrements, but that, when the per books balance is adjusted for the proposed adjustment to the June 2007 CU&LUAF true-up, the resulting balance warrants a new temporary rate decrement.

Public Staff witness Larsen testified that, in calculating these temporary decrements, he used the fixed gas cost apportionments and volumes levels by class that are set out in the stipulation in PSNC's general rate case proceeding, Docket No. G-5, Sub 495. He further stated that, if the Commission concludes in that docket that different fixed gas cost apportionments and class volumes should be approved, he recommend that the balance be calculated in that manner.

PSNC witness Paton further testified that the Company did not propose temporary increments to the under-collection of the Sales Customers Only Deferred Account. She stated that the Company proposed to continue its practice of taking into consideration the balance in the Sales Customers Only Deferred Account when evaluating whether to file for a change in the benchmark cost of gas.

Witness Larsen testified that he calculated a temporary increment of $0.05291/therm that should be implemented for all sales customers. He calculated the temporary increment by dividing the debit balance in the Sales Customers Only Deferred Account as recommended by Public Staff witness Perry by the sales volumes as determined in PSNC's general rate case proceeding, Docket No. G-5, Sub 495.

In her rebuttal testimony, Company witness Paton agreed with Public Staff witness Larsen's calculations of the temporary decrements for the All Customers Deferred Account and the temporary increment to the Sales Customers Only Deferred Account.

Based upon the foregoing, the Commission concludes that it is appropriate for PSNC to remove all temporary rates that were implemented in Docket No. G-5, Sub 488, and implement the temporary decrements and increments recommended by Public Staff witness Larsen and agreed to by Company witness Paton. Furthermore, the Commission notes that the fixed gas cost apportionments used by witness Larsen in this docket are the same as approved by the Commission in its October 24, 2008, Order in PSNC's general rate case, Docket No. G-5, Sub 495.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the twelve-month period ended March 31, 2008, is approved;

2. That the gas costs incurred by PSNC during the twelve-month period ended March 31, 2008, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein;

3. That the Company be allowed a waiver of R1-17(k)(4)(c) as it applies to the June 2007 and June 2008 Company Use and Lost and Unaccounted For true-ups;

4. That the Company shall provide a Hedging Status Report and a reconciliation of the Hedging Status Report to the Hedging Deferred Account Report for hedging activities beginning in January 2009;

5. That the Company shall remove all temporary rates that were implemented in Docket No. G-5, Sub 488; implement the temporary rate decrements to refund the All Customers Deferred Account balance as shown on Exhibit 1 attached hereto; and implement a temporary rate increment of $0.05291/therm for all sales customers effective for service rendered on and after January 1, 2009; and

6. That PSNC shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of December 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG1229008.01

DOCKET NO. G-40, SUB 71

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Frontier Natural Gas Company, LLC, for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	)	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, March 4, 2008, at 10:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners Robert V. Owens, Jr., and Howard N. Lee

APPEARANCES:

For Frontier Natural Gas Company, LLC:

Karen M. Kemerait, Blanchard, Miller, Lewis, & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

Elizabeth Denning Szafran, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On December 3, 2007, Frontier Natural Gas Company, LLC (previously named Frontier Energy, LLC) (Frontier or Company), filed the direct testimony and exhibits of David C. Shipley, President of Frontier, in connection with the annual review of Frontier's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), as modified for Frontier by the Commission's April 26, 2001 Order in Docket No. G-40, Sub 15.

On December 12, 2007, the Commission issued an order scheduling a hearing on March 4, 2008, at 10:00 a.m., setting other procedural deadlines, issuing discovery deadlines and guidelines, and requiring public notice.

On February 18, 2008, the Public Staff filed the direct testimony of Jeffrey L. Davis, Director, Natural Gas Division; David A. Poole, Accountant - Natural Gas Section, Accounting Division; and Thomas W. Farmer, Jr., Director, Economic Research Division.

On February 27, 2008, Frontier filed revised exhibits, as well as a letter stating that the Company and the Public Staff had reached agreement on all issues in the docket and requesting that the prefiled direct testimony of its witness be admitted into evidence without the need for him to appear at the hearing.

On February 28, 2008, Frontier filed the rebuttal testimony of Mr. Shipley. Also on that date, the Public Staff filed a letter requesting that the prefiled testimony of its witnesses be entered into the record.

On March 3, 2008, Frontier filed Affidavits of Publication indicating that customer notice had been provided in accordance with the Commission's procedural order.

No other parties intervened.

The matter came on for hearing as scheduled. The testimony and exhibits of Frontier witness Shipley and the testimony of Public Staff witnesses Davis, Poole, and Farmer were entered into the record. No public witnesses appeared to testify.

On April 3, 2008, Frontier and the Public Staff filed a Joint Proposed Order.

Based on the testimony, exhibits, and the record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a limited liability company organized and existing under the laws of the State of North Carolina, headquartered in Elkin, North Carolina. Frontier is a subsidiary of Energy West, Inc., and is engaged in the business of transporting, distributing, and selling natural gas in North Carolina. Frontier is a public utility as defined in G.S. 62-3(23), and its public utility operations are subject to the jurisdiction of this Commission.

2. Frontier is a natural gas local distribution company (LDC), primarily engaged in the purchase, transportation, distribution, and sale of natural gas to approximately 712 customers in North Carolina, as of November 20, 2007.

3. Frontier has filed with the Commission and submitted to the Public Staff all information required by G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), and has complied with the procedural requirements of such statute and rule.

4. The review period for this proceeding is the twelve months ended September 30, 2007.

5. During the review period, Frontier incurred gas costs of $1,510,124, composed of Gas Purchases for Delivery of $1,270,565, Demand Charges of $207,467, Pipeline Transportation Charges of $22,586, and Scheduling Fees of $9,506.

6. The appropriate Deferred Gas Cost Account balance for Frontier as of September 30, 2007, is $21,859 owed to ratepayers. The balance is comprised of a beginning balance on October 1, 2006, of $15,978 owed to ratepayers, commodity cost under-collections of $6,324, transportation customer balancing over-collections of $11,557, and accrued interest owed to ratepayers of $648.

7. Frontier has properly accounted for its gas costs during the review period.

8. The bundled supply contract Frontier has entered into has the flexibility to adapt to changing conditions and rapid growth while also providing dependable service to meet Frontier's customers' requirements.

9. Frontier has adopted a gas supply policy that it refers to as a "best evaluated cost" supply strategy. This gas supply policy is based upon flexibility, security/creditworthiness, and reliability of supply.

10. Frontier's decision not to implement a hedging program at this time was reasonable and prudent for this review period.

11. The gas costs incurred by Frontier during the review period were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

These findings of fact are essentially informational, procedural, and jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and by the testimony and exhibits filed by Frontier witness Shipley.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings of fact is found in the testimony and exhibits of Frontier witness Shipley, the testimony of Public Staff witnesses Davis and Poole, and the provisions of G.S. 62-133.4(c) and Commission Rule R-1-17(k)(6).

G.S. 62-133.4(c) requires Frontier to submit to the Commission specified information and data for a historical 12-month review period, including its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. In addition, Commission Rule R1-17(k)(6)(c) requires the filing of work papers, direct testimony, and exhibits supporting the information filed.

An examination of witness Shipley's testimony and exhibits confirms that Frontier has complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), as applied to Frontier in the Commission's Order in Docket No. G-40, Sub 15. Witness Shipley testified that Frontier filed with the Commission, and provided to the Public Staff, its updated monthly accounting of the computations required by Commission Rule R1-17(k)(5)(c) in a timely manner. Attached to witness Shipley's testimony were schedules with the information required in gas cost review proceedings pursuant to the Commission's Order in Docket No. G-100, Sub 58, issued August 18, 1992. Public Staff witnesses Davis and Poole stated that they had reviewed the data filed by Frontier in this proceeding.

The Commission concludes that based on the testimony and exhibits and the Commission's Order in Docket No. G-40, Sub 15, Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and applicable provisions of Commission Rule R1-17(k) for the review period ended September 30, 2007.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence for these findings of fact is found in the testimony and exhibits of Frontier witness Shipley and the testimony of Public Staff witnesses Poole and Davis.

Frontier witness Shipley's testimony and revised exhibits show that the components of Frontier's gas costs for the review period were as follows: Commodity Costs at City Gate of $1,270,565, Demand Fees of $207,467, Pipeline Transportation Charges of $22,586, and Scheduling Fees of $9,506. Public Staff witness Poole agreed with these amounts. The total resulting gas costs is $1,510,124.

Witness Poole further testified that each month the Public Staff reviews the deferred gas cost account reports filed by Frontier for accuracy and reasonableness and performs many audit procedures on the calculations. Public Staff witness Davis testified that the Public Staff also considers other information provided in data request responses to anticipate the Company's requirements in relation to future needs, and that the information received and reviewed includes design day estimates, forecasted load duration curves, forecasted gas supply needs, projection of capacity additions and storage changes, and customer load profile changes.

As of October 1, 2006, Frontier's beginning balance in its Deferred Gas Cost Account was $15,978 owed to ratepayers. After reflecting the commodity cost under-collections of $6,324, transportation customer balancing over-collections of $11,557, and accrued interest of $648, Frontier's Revised Schedule 8 reflects an ending balance owed to ratepayers by the Company, as of September 30, 2007, of $21,859.

Public Staff witness Poole also testified that Frontier has properly accounted for its gas costs during the review period.

Based on the reasons stated above, the Commission concludes Frontier has properly accounted for its gas costs during the review period and that the deferred account balance as reported is correct.

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

The evidence for these findings of fact is found in the testimony of Frontier witness Shipley and the testimony of Public Staff witnesses Davis and Farmer.

Frontier witness Shipley testified that Frontier's gas supply policy is best described as a "best evaluated cost" supply strategy. This gas supply strategy is based upon several criteria: flexibility, security/creditworthiness, reliability of supply, cost of the gas, and quality of supplier customer service. The foremost criteria for Frontier are flexibility, security/creditworthiness, and reliability of supply.

Witness Shipley stated that this flexibility is required because of the daily changes in Frontier's market requirements caused by the unpredictable nature of weather, the production levels/operating schedules of Frontier's industrial customers, the industrial customers' ability to switch to alternative fuels, and the growth of customers during the test period. While Frontier's gas supply agreement has different purchase commitments and swing capabilities (i.e., the ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the seasonal, monthly, daily, and hourly changes in Frontier's market requirements. Witness Shipley further testified that Frontier understands the necessity of having security of supply to provide reliable, dependable natural gas service, and has demonstrated its ability to do so. Frontier's supply strategy and its contract implementing this strategy have allowed Frontier to accomplish this objective.

In order to accomplish these objectives and implement its strategy during the review period, Company witness Shipley testified that Frontier acquired all of its natural gas requirements from Prior Energy Corporation, a wholesale gas supplier with interstate capacity. This source of capacity has proven to be reliable even during the coldest peak winter days. The gas supply contract Frontier negotiated has the flexibility and reliability to meet its market requirements in a secure and cost effective manner. He testified that Frontier continues to evaluate its gas procurement practices and plans in order to meet short-term and long-term requirements in the future.

Public Staff witness Davis testified that Frontier is still considered to be a relatively new company that began construction of its natural gas transmission and distribution systems over nine years ago. In July 2002, the Company completed construction of its transmission system throughout its franchised service area; however, the Company continues to construct its distribution pipelines to provide service to new customers in its six franchised counties. Witness Davis further testified that the first customers to attach to Frontier's system were industrial customers, with relatively few residential and commercial customers. The majority of the industrial customers were offered initial conversion rates to switch from alternative fuels and were offered negotiated rates to remain on natural gas service, and are designated to be interruptible should the system requirements justify it.

Witness Davis also testified that, given this type of customer profile, firm long-term capacity contracts similar to those used by the mature LDCs would have been more expensive due to the fact that firm capacity demand costs would have to be paid whether or not the interruptible load was using gas for a given month or if the load was lost to alternative fuels because of price sensitivity. Moreover, system throughput continues to rise as more customers are added to the system. In this environment, flexibility of supply to adapt to changing conditions and growth is essential. The contract that Frontier has entered into with its supplier has flexibility while providing dependable service to meet Frontier's customers' requirements.

Company witness Shipley testified that Frontier did not engage in any hedging activities during the review period. As a small, greenfield LDC, Frontier must carefully weigh the risk of its bundled (full) service load being less than one standard hedging contract of 10,000 dekatherms (dts) in any given month. Witness Shipley's Schedule 10 shows that, for the review period, Frontier was below 10,000 bundled (full) service dts for (5) five months and above 10,000 dts for (7) seven months. Witness Shipley further stated that as Frontier matures and its bundled (full) service load grows, it will continue to give hedging adequate scrutiny.

Public Staff witness Farmer testified that Frontier's actions related to hedging were reasonable and prudent for this review period. Witness Farmer recommended that Frontier continue to develop its hedging expertise, closely monitor gas prices, evaluate hedging opportunities, and pursue hedges when conditions warrant.

Based on the Public Staff's investigation and review of the data filed in this docket, Public Staff witness Davis testified that Frontier's gas costs during the review period were prudently incurred.

The Commission concludes that the gas costs incurred by Frontier during the twelve-month period ended September 30, 2007, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

IT IS, THEREFORE, ORDERED AS FOLLOWS:

1. That Frontier's accounting for gas costs during the review period ending September 30, 2007, is approved; and

2. That the gas costs incurred by Frontier during the twelve-month period ended September 30, 2007, were reasonable and prudently incurred, and Frontier is hereby authorized to recover its gas costs as provided herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of April, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

wg041608.01

DOCKET NO. G-41, SUB 25

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Toccoa Natural Gas for	)	
Annual Review of Gas Costs Pursuant	)	ORDER ON ANNUAL REVIEW OF
To G.S. 62-133.4(c) and Commission	)	GAS COSTS
Rule R1-17 (k)(6)	)	

HEARD: Tuesday, November 4, 2008, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding, Chairman Edward S. Finley, Jr., and Commissioner Lorinzo L. Joyner

APPEARANCES:

For Toccoa Natural Gas:

Stephon J. Bowens, Blanchard, Miller, Lewis & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

For the Using and Consuming Public:

Antoinette R. Wike, Director, Chief Counsel, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On September 5, 2008, Toccoa Natural Gas ("Toccoa" or "Company") filed the direct testimony and exhibits of Company witnesses Rai Trippe, Member Support Business Analyst for the Municipal Gas Authority of Georgia (Gas Authority), and Alan Yearwood, Gas Director for the City of Toccoa, Georgia, in connection with the annual review of Toccoa's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) for the period July 1, 2007, through June 30, 2008.[1]

On September 9, 2008, Toccoa filed Revised Trippe Exhibit 3, Schedule 8 – Summary of Deferred Gas Cost Account Activity.

On September 12, 2008, the Commission issued its Order Scheduling Hearing, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of Tuesday, November 4, 2008, set prefiled testimony dates, and required Toccoa to give at least 30 days prior notice to its customers of the hearing on this matter.

On October 20, 2008, the Public Staff filed the direct testimony of David A. Poole, Staff Accountant, Accounting Division; the direct testimony of Richard C. Ross, Public Utilities Engineer, Natural Gas Division; and the affidavit of Thomas W. Farmer, Jr., Director, Economic Research Division. No other party filed testimony.

On October 22, 2008, Toccoa filed a Consent Motion for Leave to Have Annual Review Testimony Entered into the Record and its Exhibits Admitted into Evidence (Consent Motion). The Commission issued its Order allowing the testimony to be entered into the record and exhibits admitted into evidence on October 28, 2008.

On October 30, 2008, the Company filed its Affidavit of Publication.

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[1] On August 29, 2008, Toccoa filed a Motion for Extension of Time to File Direct Testimony and Exhibits of its witnesses. On September 3, 2008, the Commission issued its Order Granting Motion for Extension of Time to File Direct Testimony and Exhibits.

On November 4, 2008 the matter came on for evidentiary hearing as scheduled. Pursuant to the agreement of all parties of record, the prefiled testimony and exhibits of the Company witnesses and the prefiled testimony and exhibits of the Public Staff witnesses were admitted into evidence and the parties waived cross-examination. No public witnesses appeared to testify.

On December 3, 2008, the Public Staff and Toccoa filed a Joint Proposed Order.

Based on the testimony, exhibits, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Toccoa is a public utility as defined in G.S. 62-3(23) subject to the jurisdiction of this Commission.

2. Toccoa is engaged in the business of transporting, distributing, and selling natural gas to customers in North Carolina and Georgia.

3. Toccoa has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended June 30, 2008.

5. During the period of review, Toccoa incurred total company gas costs of $11,409,541, composed of $1,149,915 of demand and storage costs, $10,259,626 of commodity costs, and $0 of other cost of gas charges/(credits). The North Carolina portion of gas costs for the review period was $582,081.

6. At June 30, 2008, Toccoa's North Carolina Deferred Gas Cost Account had a credit balance of $1,293, owed to the customers.

7. Toccoa properly accounted for its gas costs during the review period.

8. It is appropriate for Toccoa to revise Trippe Exhibit 3 in its next annual review proceeding to present both the total company cost of gas and the North Carolina allocated cost of gas.

9. Toccoa has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Toccoa's system and an "all requirements" gas supply contract with the Gas Authority.

10. Toccoa released unutilized capacity during the review period to mitigate the cost of extra demand capacity, and all of the margins earned on secondary market transactions reduced the cost of gas and flowed through to ratepayers.

11. Toccoa has adopted a "portfolio approach" gas purchasing policy consisting of four main components: long-term firm supply, short-term spot market purchases, seasonal peaking, and contract storage services.

12. Toccoa's hedging activities during the review period were prudent.

13. The Company's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

14. The Company should be permitted to recover 100% of its prudently incurred gas costs.

15. It is reasonable for Toccoa to implement a temporary rate decrement in the amount of $0.0366 per dekatherm for all North Carolina firm customers effective February 1, 2009.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 2

The evidence supporting these findings is contained in the official files and records of the Commission and the testimony of Toccoa witnesses Trippe and Yearwood. These findings are essentially informational, procedural, or jurisdictional in nature and are based on evidence uncontested by any of the parties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 – 4

The evidence supporting these findings is contained in the testimony of Toccoa witnesses Trippe and Yearwood, the testimony of Public Staff witnesses Poole and Ross, the affidavit of Public Staff witness Farmer, and the Commission's Rules.

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical twelve-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes June 30, 2008, as the end date for the review period in this proceeding. Commission Rule R1-17(k)(6)(c) requires the filing by Toccoa of certain information and data showing weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Company witness Trippe testified that Toccoa filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(6)(c). Public Staff witness Poole confirmed that the Public Staff reviewed the filings and monthly reports filed by Toccoa. No other party filed testimony or presented evidence on this matter.

The Commission, therefore, concludes that Toccoa has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 – 8

The evidence supporting these findings is contained in the testimony of Toccoa witness Trippe and Public Staff witness Poole.

Public Staff witness Poole states that Toccoa's total company cost of gas for the current review period was $11,409,541. Poole Exhibit I reflects total company demand and storage costs of $1,149,915, and commodity costs of $10,259,626, as well as the North Carolina allocated gas costs incurred of $582,081. Witness Poole also testified that Toccoa had properly accounted for its gas costs during the review period.

Witness Poole testified that Trippe Exhibit 3 reflected total company amounts for demand and commodity charges combined with the North Carolina allocated amounts for other cost of gas charges. He further stated that Toccoa did not provide a North Carolina allocated cost of gas amount in Trippe Exhibit 3. Poole Exhibit I reflects a total company cost of gas that corrects (1) the total company other cost of gas amount, as well as (2) the "Hedge Option 2 – MGAG Directed" adjustment in order to be consistent with the Revised Trippe Exhibit 3, Schedule 8 - Summary of Deferred Gas Cost Account Activity. Witness Poole also testified that Toccoa has agreed to revise its exhibits in the next annual review proceeding to present both the total company cost of gas and the North Carolina allocated cost of gas as shown on Poole Exhibit 1.

Company witness Trippe testified that Toccoa's deferred account beginning balance at July 1, 2007 was ($34,905). Witness Trippe also stated that Toccoa had maintained rates sufficient throughout the year to recover costs. Company witness Trippe revised Trippe Exhibit 3, Schedule 8 to reflect a corrected June 30, 2008 deferred account balance of $1,293.

Public Staff witness Poole testified that the allocated North Carolina Deferred Gas Cost Account balance at June 30, 2008, was $1,293, a credit balance owed from the Company to the customers. He further testified that Toccoa maintains only one Deferred Gas Cost Account for North Carolina that includes both the commodity and demand gas charges incurred and recovered during each review period. Witness Poole stated that, prior to March 1, 2005, the Deferred Gas Cost Account was not allocated between North Carolina and Georgia because Toccoa charged the same rates in both states. He further explained that in March 2005, Toccoa agreed to allocate the Deferred Gas Cost Account, after adjusting for gas cost recoveries from Georgia ratepayers, to North Carolina based on the monthly firm sales volumes for the review period. Toccoa then began implementing increments/decrements to collect/refund its North Carolina Deferred Gas Cost Account balance for North Carolina-only customers in its annual review proceedings.

No other party filed testimony or presented evidence on these matters.

Based on the foregoing, the monthly filings by Toccoa pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Toccoa has properly accounted for its gas costs during the review period and that the Deferred Gas Cost Account balance as proposed by the Public Staff is correct. The Commission agrees with the Public Staff's recommendation that Toccoa should revise Trippe

Exhibit 3 in the next annual review proceeding to present both the total company cost of gas and the North Carolina allocated cost of gas.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 – 14

The evidence for these findings of fact is contained in the testimony of Company witness Trippe and Public Staff witnesses Poole and Ross and the affidavit of Public Staff witness Farmer.

Company witness Trippe testified that Toccoa is a charter member of the Gas Authority, which supplies its 76 member cities' gas supply needs, relying on a combination of long-term firm supply arrangements, short-term spot-market purchases, seasonal peaking, and contract storage services. He also testified that Toccoa is assured adequate, dependable, and economical gas supplies through the Gas Authority's efforts.

Public Staff witness Ross testified that he reviewed the Company's gas supply, pipeline transportation, and storage contracts. Witness Ross testified that Toccoa has eight contracts for pipeline capacity and storage service from Transco, a storage service contract with Pine Needle LNG Company, LLC, and a gas supply contract with the Gas Authority. The Gas Authority is the "all requirements" supplier for Toccoa, and as a result, the Gas Authority manages all of Toccoa's pipeline, storage service, and gas supply contracts.

Company witness Trippe further testified that the Gas Authority, on behalf of Toccoa, was able to release a portion of Toccoa's unutilized capacity each month of the fiscal period. Dollars generated during the period of July 2007 through June 2008 totaled $206,928.

Public Staff witness Poole testified that all of the margins earned on these capacity release credits flowed through 100% to ratepayers.

Company witness Trippe stated that one of the challenges for Toccoa in the development and implementation of its gas supply strategy is in the area of price hedging. A common benchmark for comparing hedged prices is the spot market price. Witness Trippe stated that this can be an unfair measure because it is available only after the fact and assumes that the goal of hedging is "to beat the market." He further stated that the goal of hedging is to achieve price stability at a reasonable level for the consuming public.

Company witness Trippe further testified that Toccoa participates in the Gas Authority's "WinterHedge" program under the Authority's Option 2. The Gas Authority's objective in hedging is to achieve price stability at a reasonable level for the consuming public. This is accomplished by hedging up to approximately 50% of Toccoa's firm load.

Public Staff affiant Farmer testified that Toccoa's hedging activities were reasonable and prudent and that the Company's net hedging costs of $1,304 incurred during this review period should be reflected in costs to ratepayers.

No other party filed testimony or presented evidence on these matters.

Based on the foregoing, the Commission concludes that Toccoa's gas purchasing policies and practices, as well as its hedging activities, were reasonable and prudent and that its gas costs during the review period were reasonably and prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony of Company witness Trippe and Public Staff witness Ross.

Public Staff witness Ross proposed that a rate decrement of $0.0366 per dekatherm be approved for all North Carolina firm customers, effective the first day of the month following the date of the order in this proceeding. Witness Ross further testified that this new rate decrement will replace the $0.5729 per dekatherm increment that was placed in rates on February 1, 2008, as a result of Toccoa's prior annual review proceeding in Docket No. G-41, Sub 23. Witness Ross also stated that Toccoa has only one North Carolina Deferred Gas Cost Account (that includes both demand and commodity gas costs), and this will be the only temporary rate element in rates.

Toccoa agreed with the Public Staff's findings and recommendations as indicated in its October 22, 2008 Consent Motion.

No other party filed testimony or presented evidence on this matter.

Based on the foregoing, the Commission concludes that a temporary decrement of $0.0366 per dekatherm should be implemented for all North Carolina firm customers effective the first day of the month following the date of the order in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That Toccoa's accounting for gas costs during the twelve months ended June 30, 2008, is approved;

2. That Toccoa is authorized to recover 100% of its gas costs incurred during the twelve months ended June 30, 2008;

3. That the Company shall remove the temporary rate increment that was implemented in Docket No. G-41, Sub 23, and implement a temporary rate decrement of $0.0366 per dekatherm for all of its North Carolina firm customers, effective for service rendered on and after February 1, 2009; and

4. That, in its next annual review proceeding, the Company shall revise Trippe Exhibit 3 to present both the total company cost of gas and the North Carolina allocated cost of gas.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG1230008.01

DOCKET NO. G-5, SUB 495

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of North Carolina, Inc., for a General Increase in its Rates and Charges	))))	ORDER APPROVING PARTIAL RATE INCREASE AND REQUIRING CONSERVATION PROGRAM FILING AND REPORTING

HEARD IN: Iredell County Hall of Justice, Statesville, North Carolina on July 8, 2008; Public Works Building, Asheville, North Carolina on July 8, 2008; Gastonia County Courthouse, Gastonia, North Carolina on July 9, 2008; Durham Chamber of Commerce, Durham, North Carolina on July 10, 2008; and the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina on July 14, 2008, and August 26, 2008

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Robert V. Owens, Jr.; Sam J. Ervin, IV; Howard N. Lee; and William T. Culpepper, III

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

B. Craig Collins, SCANA Corporation, 1426 Main Street, Columbia, South Carolina 29218

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For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205 Raleigh, North Carolina 27609

NATURAL GAS – RATE INCREASE

BY THE COMMISSION: On February 27, 2008, Public Service Company of North Carolina, Inc. (PSNC or Company), gave notice pursuant to Commission Rule R1-17(a) of its intent to file a general rate case.

On March 10, 2008, Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene, which the Commission granted on March 11, 2008. On March 12, 2008, the Attorney General of North Carolina (Attorney General) filed his notice of intervention.

On March 31, 2008, PSNC filed its verified application for a general rate increase (Application). Included with the Application were the data required by NCUC Form G-1, and the direct testimony and exhibits of D. Russell Harris, Jimmy E. Addison, Dr. Donald R. Murry, Dr. Julius A. Wright, Sharon D. Boone, and Candace A. Paton.

By Order issued April 30, 2008, the Commission declared the Company's Application to be a general rate case pursuant to G.S. 62-137 and suspended the proposed rates for a period of 270 days from and after May 1, 2008. In that Order, the Commission also set the matter for hearing, required the Company to give notice of hearing, established discovery guidelines, and established dates for interventions and for the prefiling of direct testimony by intervenors and rebuttal testimony by the Company.

On May 30, 2008, PSNC filed an amendment to its Application providing supplemental NCUC Form G-1 data.

On June 25, 2008, PSNC filed its affidavits of publication of public notice.

On June 30, 2008, PSNC filed a Motion for Admission to Practice and Statements of PSNC and B. Craig Collins pursuant to G.S. 84-4.1 seeking an order from the Commission allowing Mr. Collins to appear before the Commission in this proceeding. On July 8, 2008, the Commission issued an Order granting PSNC's motion. On July 22, 2008, the Company filed a Pro Hac Vice registration statement which had been provided to the Administrative Office of the Courts.

On July 8, 2008, PSNC filed a revised Item 3 of its NCUC Form G-1 and revised Exhibits 5, 6, and 7 to witness Paton's testimony.

On July 8, 2008, a hearing on the Application was held in Statesville as scheduled. At the hearing in Statesville, David Pressly, Jeff Lineberry, Lonnie Troutman, and Doug Safriet testified as public witnesses. On July 8, 2008, a hearing was held in Asheville as scheduled. At the hearing in Asheville, Keith Levi testified as a public witness. On July 9, 2008, a hearing was held in Gastonia as scheduled. At the hearing in Gastonia, Janet Puett testified as a public witness. On July 10, 2008, a hearing was held in Durham as scheduled. At the hearing in Durham, Richard Leber testified as a public witness. On July 14, 2008, a hearing was held in Raleigh as scheduled. At the hearing in Raleigh, no public witnesses testified.

On July 10, 2008, Texican Horizon Energy Marketing, LLC (Texican) filed a Petition to Intervene, which was granted by the Commission on July 18, 2008.

On August 13, 2008, the Attorney General filed the direct testimony and exhibits of Roger D. Colton.

On August 13, 2008, the Company, the Public Staff, and CUCA (the Stipulating Parties) filed a Stipulation and Exhibits (Stipulation) resolving all issues in this proceeding among the Stipulating Parties. Counsel for the Company reported that she was authorized to state that Texican did not oppose the Stipulation.

On August 15, 2008, the Company filed the supplemental testimony of Candace A. Paton in support of the Stipulation.

On August 15, 2008, the Attorney General filed a schedule that had been omitted from the direct testimony and exhibits of Roger D. Colton.

On August 20, 2008, the Attorney General filed a letter requesting that the Commission admit into evidence the testimony of Roger D. Colton without the need for him to appear at the hearing. Also, on August 20, 2008, PSNC requested that the testimony and exhibits of its witnesses D. Russell Harris, Sharon D. Boone, and Dr. Donald R. Murry be entered into evidence without the need for them to appear at the hearing.

On August 22, 2008, PSNC filed the Stipulating Parties' revised exhibits to the Stipulation.

On August 22, 2008, the Commission issued an Order granting the motions to excuse PSNC witnesses D. Russell Harris, Sharon D. Boone, and Dr. Donald R. Murry and Attorney General witness Roger D. Colton from attending the hearing and to allow their prefiled testimony to be copied into the record by stipulation of the parties.

On August 26, 2008, the hearing in Raleigh was held as scheduled. No person testified as a public witness. At the hearing, the various prefiled direct and supplemental testimony and exhibits of the following Company witnesses were offered and accepted into evidence: D. Russell Harris, Jimmy E. Addison, Dr. Donald R. Murry, Dr. Julius A. Wright, Sharon D. Boone, and Candace A. Paton. The prefiled direct testimony of Attorney General witness Roger D. Colton was also offered and accepted into evidence. Company witnesses Addison, Wright, and Paton testified at the hearing as a panel and answered questions from the Attorney General and the Commission.

On September 19, 2008, the Attorney General filed a Motion for Admission of Late-Filed Exhibits concerning evidence introduced at the August 26, 2008 hearing. In its Motion, the Attorney General requested that the updated information contained in Commission reports relating to the earnings of Piedmont Natural Gas Company, Inc. (Piedmont), which was offered into evidence at Piedmont's general rate case hearing on September 5, 2008, in Docket No. G-9, Sub 550, be provided to the record in the instant docket. The Attorney General also requested that Late-Filed Exhibit 2 be admitted as that provided Piedmont's revised earnings information in summary form.

On September 23, 2008, PSNC filed an Objection and Motion to Strike. PSNC stated that the Attorney General should not be permitted to use either his evidence related to

Piedmont's earnings presented at the August 26, 2008 hearing or the new evidence contained in the late-filed exhibits. On September 24, 2008, PSNC filed a Supplement in which PSNC identified the particular exhibits and testimony that PSNC moved to strike from the record.

On September 25, 2008, the Attorney General filed a Reply Concerning Late-Filed Exhibits. On September 26, 2008, the Commission issued an Order on Motion for Admission of Late-Filed Exhibits. In its Order, the Commission allowed the Attorney General's proposed late-filed exhibits and denied PSNC's Motion to Strike.

On October 6, 2008, the Joint Proposed Order of PSNC and the Public Staff was filed. Also, on October 6, 2008, the Attorney General filed its Brief.

Based upon the verified Application; the testimony and exhibits received into evidence at the hearings; the Stipulation; and the entire record in this proceeding, the Commission now 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 within a franchised area consisting of all or parts of 28 counties in central and western 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. The Commission has jurisdiction over the rates and charges, rate schedules, rate classifications, and practices of public utilities, including the Company.

4. In its Application in this docket, the Company sought: (i) an increase of $20,441,501 in revenues; (ii) certain changes to the cost allocations and rate designs underlying existing rates for the Company; (iii) certain revisions to the current tariff language; (iv) amortization of certain deferred account balances; (v) the implementation of a Customer Usage Tracker (CUT); and (vi) the implementation of a cost-recovery mechanism for customer conservation programs.

5. PSNC is properly before the Commission with respect to the relief sought in its Application pursuant to the provisions of Chapter 62 of the General Statutes of North Carolina.

6. The appropriate test period for use in this proceeding is the 12-month period ended December 31, 2007, updated for certain known and measurable changes through June 30, 2008.

7. The Stipulation executed by PSNC, the Public Staff, and CUCA settles all matters in this docket with respect to the Stipulating Parties and is not opposed by Texican.

8. The Attorney General, the only other party to the proceeding, had no objection to the Stipulation except for the proposed CUT mechanism.

9. The Stipulation provides for an increase in annual revenues for the Company of $9,104,984 offset by $8,376,707 of reductions in fixed gas costs, for a net increase in rates and charges of $728,277, as set forth in Paragraph 5.E of the Stipulation. This provision is just and reasonable and should be approved.

10. The Stipulating Parties agreed that the appropriate level of original cost rate base used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the Company's customers within North Carolina is $709,665,864, consisting of gas plant in service of $1,178,638,190 and working capital of $60,839,439 reduced by accumulated depreciation of $423,701,529 and accumulated deferred income taxes of $106,110,237, as described and set forth in Paragraph 4 and Exhibit A of the Stipulation. These provisions are just and reasonable and should be approved.

11. The Stipulating Parties agreed that the Company's end-of-period pro forma revenues under present rates for use in this proceeding are $687,359,831, a figure which is comprised of $683,396,160 of sales and transportation revenues, $618,496 of special contract revenues, and $3,345,175 of other operating revenues as described and set forth in Paragraph 5.A and Exhibit A of the Stipulation and that the pro forma annual operating revenues under the agreed-upon rates are $688,088,108, which includes annual sales and transportation revenues of $684,124,437, as set forth in Paragraph 5.E and Exhibit A of the Stipulation. These provisions of the Stipulation are just and reasonable and should be approved.

12. The Stipulation provides that the Company's operating expenses, including actual investment currently consumed through reasonable actual depreciation are $158,031,684, as set forth in Paragraph 5.A and Exhibit A. This provision is just and reasonable and should be approved.

13. The Stipulating Parties agreed that the overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property, as described in Finding of Fact No. 10 above, is 8.54%, as set forth in Paragraph 5.D and Exhibit A of the Stipulation, which includes a return on common equity of 10.60%, as set forth in Paragraph 5.C of the Stipulation. Further, the Stipulating Parties agreed that the appropriate capital structure consists of 54.00% common equity, 10.50% short-term debt, and 35.50% long-term debt, with the cost of short-term debt and long-term debt being 3.25% and 6.96%, respectively, as set forth in Paragraph 5.B of the Stipulation. These provisions are just and reasonable and should be approved.

14. The Stipulation provides that, for purposes of this proceeding, the appropriate level of adjusted sales and transportation volumes is 748,884,204 therms, which is comprised of 465,456,764 therms of sales quantities, 250,486,091 therms of transportation quantities and 32,941,349 therms of special contract quantities, as described and set forth in Paragraph 3.A and Exhibit B. The Stipulating Parties agreed that the appropriate level of company use gas is 726,910 therms, that the appropriate level of lost and unaccounted for gas is 5,691,520 therms and that the appropriate level of purchased gas supply is 471,875,194 therms, consisting of sales

volumes, company use gas, and lost and unaccounted for gas, as described and set forth in Paragraphs 3.B and 3.C, respectively, and Exhibit G of the Stipulation. These provisions are just and reasonable and should be approved.

15. The Stipulating Parties agreed that the fixed gas costs that should be embedded in the proposed rates and used in true-up of fixed gas costs in proceedings under Rule R1-17(k) until the resolution of PSNC's next general rate case are those derived from the fixed gas cost allocation percentages set forth in Exhibit C to the Stipulation. This provision is just and reasonable and should be approved.

16. The agreed-upon rate design and rates, including volumetric rates, fixed monthly charges, and other charges, as described in Paragraph 6 of the Stipulation and as set forth on Exhibits B and E attached thereto (as the same may be adjusted for any changes in the Company's benchmark cost of gas or changes in demand and storage charges prior to the effective date of the revised rates), are just and reasonable and should be approved.

17. The Stipulating Parties agreed to an increment of $0.00136 per therm, applicable to Rate 101, based on the October 31, 2008 rate deferral balance of $381,330 as shown on Paton Exhibit 14 and as described and set forth in Paragraph 7 of the Stipulation. Such increment is to recover the rate differential between Rate 105 and Rate 110 pursuant to the Commission's May 21, 2007 Order on Reconsideration in Docket No. G-5, Sub 481. This provision is just and reasonable and should be approved.

18. The Stipulating Parties agreed that the reasonable adjusted level for the total cost of gas in this proceeding is $468,578,855, as described in Paragraph 11.B and Exhibit G to the Stipulation. This provision is just and reasonable and should be approved.

19. The Stipulation provides that the current temporary rate decrements applicable to the All Customers Deferred Account will remain in effect until addressed by the Commission in the Company's pending annual review of gas costs in Docket No. G-5, Sub 497. This provision is just and reasonable and should be approved.

20. The Stipulating Parties agreed to charge a portion of compensation charged to PSNC for SCANA Corporation (SCANA) executives listed in its 2008 proxy statement to nonutility operations as described in Paragraph 13 of the Stipulation. This provision is just and reasonable and should be approved.

21. The Stipulating Parties agreed that the appropriate Allowance for Funds Used During Construction (AFUDC) rate for the Company should be the overall rate of return, adjusted for income taxes. This provision is just and reasonable and should be approved.

22. The Stipulation provides for the amortization of manufactured gas plant costs and pipeline integrity management costs, as set forth and described in Paragraph 12. This provision is just and reasonable and should be approved.

23. The Stipulation provides that PSNC will file its proposed conservation programs for conservation communications, in-home energy audits, energy efficiency equipment rebates, and high-efficiency discount rates for approval within 30 days of this Order. The Stipulation

also provides that PSNC will be allowed to recover $750,000 of conservation program expenditures through the cost of service in this proceeding. These provisions are just and reasonable and should be approved subject to the additional filing and reporting requirements as set forth hereinafter.

24. The proposed CUT, as described in Paragraph 9 and set forth in Exhibit E to the Stipulation, and the proposed "R" values, base load, and heat sensitive factors, as set forth in Exhibit D to the Stipulation, are appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in this general rate case proceeding. The proposed CUT mechanism is in the public interest and should be approved. As a consequence, the corresponding termination of the Weather Normalization Adjustment (WNA) mechanism in the Company's tariffs is just and reasonable and should be approved.

25. The agreed-upon tariffs, attached to the Stipulation as Exhibit E, are just and reasonable and should be approved.

26. The agreed-upon changes to the Rules and Regulations, which are reflected in Exhibit F of the Stipulation, are just and reasonable and should be approved.

27. All of the provisions of the Stipulation are just and reasonable under the circumstances of this proceeding and should be approved, subject to the additional filing and reporting requirements related to the conservation program process as set forth hereinafter.

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

The evidence supporting these findings of fact is contained in the Company's verified Application; the testimony and exhibits of the various witnesses; the NCUC Form G-1 that was filed with the Application, as modified; the provisions of Chapter 62 of the General Statutes; and the Commission's records as a whole. These findings are primarily jurisdictional and informational and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The Company filed its Application and exhibits using a test period consisting of the 12 months ended December 31, 2007. In its April 30, 2008 Order in this docket, the Commission ordered the parties to use a test period consisting of the 12 months ended December 31, 2007, with appropriate adjustments. The Stipulation is based upon the test period ordered by the Commission, and this test period was not contested by any party. In the Stipulation, the Stipulating Parties agreed to make appropriate adjustments to the test period data for circumstances occurring or becoming known through June 30, 2008. These adjustments were not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding is supported by the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulation recites that it was filed on behalf of PSNC, the Public Staff, and CUCA. The Stipulation provides that it represents a settlement of all the Stipulating Parties' issues in the proceeding. Counsel for the Company stated that she was authorized by Texican's counsel to represent that Texican takes no position regarding the Stipulation and does not oppose it.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

This finding is supported by the statements of counsel for the Attorney General.

Assistant Attorney General Margaret A. Force stated at the hearing of this matter that the Attorney General opposes the CUT mechanism, but in other respects does not object to the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

This finding is supported by the Application; the direct testimony of Company witness Boone; supplemental testimony of Company witness Paton; the Stipulation; and the testimony of Company witness Paton at the hearing.

Boone Exhibit 6 reflects that the Company filed for a net revenue increase of $20,441,501 in its Application. The Stipulation in Paragraph 5.E provides that the Company should be allowed to increase its annual level of margin through the rates and charges approved in this case by $9,104,984, offset by $8,376,707 of reductions in fixed gas costs, for a net annual increase in rates and charges of $728,277. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The reasonable original cost of the Company's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within its service territory, less that portion of the cost which has been consumed by depreciation expense, is described and set forth in Paragraph 4 and Exhibit A to the Stipulation and reflected on Schedule 1 included herein.

The amounts provided in Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and in the supplemental testimony of Company witness Paton, and are not opposed by any party. The stipulated reasonable original cost of the Company's property used and useful or to be used and useful within a reasonable time after the test period, in providing natural gas service to the public, less depreciation expense, is not contested by any party. The Commission has carefully reviewed these amounts, as well as all the record evidence relating to the Company's rate base, and concludes that the stipulated amounts are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The end-of-period pro forma revenues under the Company's present and stipulated rates are set forth in Paragraph 5.A and Exhibit A to the Stipulation and reflected on Schedule 1 included herein.

The amounts on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and the supplemental testimony of Company witness Paton, and are not contested by any party. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's pro forma revenues, and concludes that the stipulated pro forma revenues are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The Company's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are set forth in Paragraph 5.A and Exhibit A to the Stipulation and reflected on Schedule 1 included herein.

The amounts on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and the supplemental testimony of Company witness Paton, and are not contested by any party. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's reasonable operating expenses, and concludes that the stipulated reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The overall rate of return on the cost of the Company's used and useful property is set forth in Paragraph 5.D and Exhibit A to the Stipulation and reflected on Schedule 1 included herein. The overall rate of return, the return on common equity, and the capital structure are the result of negotiations among the Stipulating Parties, as described in the Stipulation and the supplemental testimony of Company witness Paton, and they are not contested by any party. The Stipulation stated, and Company witness Addison testified at the hearing, that the stipulated return on common equity is lower than what the Company would otherwise have agreed to if the Stipulating Parties had not agreed, among other considerations, to the implementation of the CUT mechanism. The Commission has carefully reviewed the stipulated overall rate of return, the return on common equity, and the capital structure and the evidence of record relating to rate of return and concludes that the stipulated overall rate of return, the return on common equity, and the capital structure are just and reasonable.

The Commission also concludes that the stipulated overall rate of return and return on common equity will allow the Company, by sound management, the opportunity to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they now exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The level of adjusted sales and transportation volumes used in the Stipulation is 748,884,204 therms as shown on Exhibit B and the level of purchased gas supply as shown on

Exhibit G to the Stipulation is 471,875,194 therms. The throughput volume level is derived as follows:

Item	Amount (therms)
Sales	465,456,764
Transportation	250,486,091
Special Contracts	32,941,349
Total Throughput	748,884,204

The level of purchased gas supply is 471,875,194 therms, derived as follows:

Item	Amount (therms)
Sales	465,456,764
Company Use	726,910
Lost & Unaccounted for	5,691,520
Total Gas Supply	471,875,194

The throughput level and level of purchased gas supply are the result of negotiations among the Stipulating Parties, as described in Paragraph 3 of the Stipulation, and are not opposed by any party. The Commission has carefully reviewed this throughput level and concludes that it is a just and reasonable approximation of the Company's pro forma adjusted sales and transportation volumes. The Commission has also carefully reviewed the purchased gas supply level and concludes that it is a just and reasonable approximation of the Company's pro forma purchased gas supply level.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

Under the Commission's procedures for truing-up fixed gas costs in proceedings under Rule R1-17(k), it is necessary and appropriate to determine the amount of fixed gas costs that are embedded in the rates approved herein. In Paragraph 8 of the Stipulation, the Stipulating Parties agreed that, for the purpose of this proceeding and future proceedings under R1-17(k), the appropriate amount of fixed gas costs allocated to each rate schedule is set forth below, as well as in Exhibit C to the Stipulation:

Rate Schedule	Description	Fixed Gas Cost Unit Rate ($/therm)	Fixed Gas Cost Apportionment %
101 – Summer	Residential	$0.07790	5.700%
101- Winter	Residential	$0.13790	59.178%
125 – Step 1	Small General Service	$0.13532	17.026%
125 – Step 2	Small General Service	$0.08176	9.019%
125 – Step 3 & Rate 126	Small General Service	$0.04272	0.280%
145	LGS Firm Sales	$0.05436	2.092%
150	LGS Interruptible Sales	$0.03392	1.775%
175	Firm Transportation	$0.01114	1.442%
180	Interruptible Transportation	$0.01089	3.489%

These amounts were not contested by any party. The Commission has carefully examined these amounts, as well as all record evidence on fixed gas cost allocations, and concludes that the stipulated allocations of fixed gas costs are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding is contained in the Application; in Paragraph 6 of the Stipulation and Exhibits B and E attached thereto; in the direct and supplemental testimony of Company witness Paton; and in the testimony of Attorney General witness Colton.

The computation of revenues under the proposed rates (based on a Benchmark Commodity Cost of Gas of $0.875 per therm) is set forth on Exhibit B to the Stipulation. These computations show that the proposed rates will produce the revenues calculated under the rate design approved for use in this proceeding.

In its Application, the Company proposed to increase monthly facilities charges for residential customers on Rate Schedule 101 from $10.00 to $12.00 and for commercial customers on Rate Schedule 125 from $17.50 to $20.00. Attorney General witness Colton testified that elderly and low-income customers use less natural gas and that, therefore, PSNC's proposal to raise residential facilities charges from $10 per month to $12 per month would disproportionately burden low-income customers. Witness Colton also testified that the proposed rate structure will shift risks from PSNC's shareholder to its customers.

In the Stipulation and as reflected in the supplemental testimony of Company witness Paton, the Stipulating Parties agreed to retain the $10.00 monthly facilities charge for residential customers and the $17.50 monthly facilities charge for commercial customers, a proposal which is not opposed by any party. The Commission concludes that the monthly facilities charges reflected in the Stipulation are appropriate and should be approved.

With respect to the issue of the appropriate rates and rate design for use in this proceeding, Company witness Paton testified in her supplemental testimony that the proposed rates and underlying rate design reflected in Exhibit B to the Stipulation are just and reasonable and fair to consumers and the Company in the context of the Stipulation as a whole. The Stipulating Parties agreed that these rates are proper, just and reasonable. Witness Paton's conclusions and the conclusions set forth in the Stipulation are uncontested.

The Commission has carefully reviewed these rates, as well as all record evidence relating to the proper rates to be implemented in this proceeding, and concludes that the stipulated rates are just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding is contained in Paragraph 7 of the Stipulation and the testimony of Company witness Paton.

In the Commission's May 21, 2007 Order on Reconsideration in PSNC's prior rate case in Docket No. G-5, Sub 481, the Commission ordered PSNC to defer the rate differential between Rate 105 and Rate 110 beginning June 1, 2007, for a period no longer than November 1, 2007, and to accrue interest at the Company's net-of-tax overall rate of return. The Stipulating Parties agreed to establish an increment of $0.00136 per therm, applicable to Rate 101, based on the October 31, 2008 rate deferral balance of $381,330 shown on Paton Exhibit 14. Company witness Paton testified at the hearing that the Company will file monthly updates in deferred account reports tracking recovery of the balance.

The agreed-upon increment is not contested by any party. The Commission has fully considered this provision of the Stipulation and concludes that it is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding is contained in Paragraph 11.B of the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulating Parties support the adjusted level of total cost of gas after the rate increase as described in Paragraph 11.B of the Stipulation. No party has contested this level. The Commission has carefully examined the amounts set forth in Paragraph 11.B of the Stipulation and finds that they are just and reasonable and concludes they should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding is contained in the testimony at the hearing of Company witness Paton.

At the hearing, witness Paton testified that existing decrements will remain in place until the Commission's order in the Company's pending annual review of gas costs proceeding, Docket No. G-5, Sub 497, at which time new temporaries will be determined.

The Commission has carefully reviewed the proposed treatment of the temporary rate decrements and concludes that they are just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding is found in the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulating Parties agreed to charge a portion of compensation charged to PSNC for SCANA executives listed in its 2008 proxy statement to nonutility operations as described in Paragraph 13 of the Stipulation. No party opposed this provision of the Stipulation.

The Commission has carefully reviewed this provision of the Stipulation and concludes that it just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding is contained in Paragraph 15 of the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulating Parties agreed that the appropriate AFUDC rate for the Company, effective November 1, 2008, should be the agreed-upon overall rate of return, adjusted for income taxes. No party objected to this provision of the Stipulation. Company witness Paton testified in response to a question from the Commission that the AFUDC rate would remain in effect until the Company's next general rate case proceeding.

The Commission has carefully reviewed this provision of the Stipulation and concludes that the agreed-upon AFUDC rate is just and reasonable and should be adopted and should remain in effect until PSNC's next general rate case proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence for this finding is contained in the Company's Application and the direct testimony of Company witnesses Boone and Paton, the Stipulation, and the supplemental testimony of Company witness Paton.

The Stipulation provides certain agreed-upon amounts and amortization periods for the treatment of deferred manufactured gas plant costs and deferred pipeline integrity management costs as of June 30, 2008, as described and set forth in Paragraph 12. The Stipulating Parties agreed that the appropriate amount of deferred manufactured gas plant costs was $3,494,563; the appropriate amount of deferred pipeline integrity management costs was $2,287,037; and that both deferred amounts should be amortized over three years. The Stipulating Parties further agreed that it is appropriate to continue, until the resolution of PSNC's next general rate case proceeding, the regulatory asset treatment for costs paid to outside contractors and outside consultants incurred as a result of the Pipeline Safety Improvement Act of 2002, pending the establishment of an appropriate recovery mechanism in a future proceeding.

No party contested the provision of the Stipulation contained in Paragraph 12. The Commission has carefully considered the agreed-upon amounts and amortization periods and related matters set forth in Paragraph 12 of the Stipulation, as well as all record evidence on the amortization of these deferred costs, and concludes that the stipulated amounts and amortization periods are just and reasonable and should be approved. The Commission further concludes that the proposed continuation of regulatory asset treatment for pipeline integrity management costs is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence for this finding is found in PSNC's Application; the prefiled direct testimony of Company witnesses Harris, Paton, and Wright; the Stipulation; the supplemental testimony of witness Paton; and the testimony at the hearing.

In its Application, subject to the Commission's authorization of the proposed CUT mechanism, PSNC proposed to file conservation programs and to discontinue its WNA mechanism. PSNC observed that the current volumetric rate structure causes a disincentive for the Company to promote energy efficiency and conservation measures for its customers. PSNC remarked that the decoupling of margin from usage will better align the interests of the Company and its customers with respect to conservation, which is particularly important in today's environment. PSNC proposed the following four conservation initiatives (three programs and the discount rates initiative): (1) a communications program that would educate customers and encourage conservation including an "Energy Conservation School Initiative"; (2) an in-home energy audit program that would provide for weatherization and conservation measures to be installed at the time of the visit; (3) an energy efficiency rebate program where appliances such as tankless water heaters, commercial water heaters with a high thermal efficiency, and furnaces with an annual fuel utilization efficiency (AFUE) greater than 90% would qualify for a rebate; and (4) discount rates for high-efficiency residential homes and commercial buildings that meet certain energy efficiency standards, including Energy Star standards and Leadership in Energy and Environmental Design (LEED) certification.

PSNC witnesses Paton and Addison testified that PSNC's programs were not filed prior to or as a part of the case since the programs were dependent upon PSNC receiving approval to implement the CUT and the programs were still being developed. PSNC witness Wright explained that the primary objectives that PSNC believes are important in identifying appropriate conservation and efficiency programs are the following: (1) the initiative should produce actual and identifiable conservation benefits and have lasting impact, (2) the initiative should be beneficial and valuable to PSNC's customers, and (3) the initiative should be easy to understand and communicate to customers. Witness Wright testified that the Company's proposed conservation initiatives would meet these primary objectives.

Further, witness Wright stated that the Company had proposed that the three programs be paid for by customers using the true-up mechanism detailed in witness Paton's testimony and remarked that customers would be responsible for paying only those costs that are actually incurred. Witness Wright explained that, after approval of the three programs is obtained, any funds used for these programs would be recorded in a separate account up to a limit of $1.3 million per year. Although PSNC did not ask the Commission to approve the three programs and related costs in its initial filing, it stated that it would file for approval of its proposed programs within 60 days after an order was issued approving the Company's CUT and its mechanism for recovering the cost of conservation programs.

In prefiled testimony, witness Paton stated that, with regard to the Company's initiative regarding discount rates, PSNC proposed to discount the fixed gas cost components of Rates 101 (Residential) and 125 (Small General Service) to determine the rates applicable to Rates 102 (High-Efficiency Residential) and 127 (High-Efficiency Small General Service). Therefore, the cost of the discounts would be recovered through the normal fixed gas cost true-up procedure. For the other three initiatives, witness Paton observed that the Company had proposed to defer, track, and true-up actual program expenses. Witness Paton explained that, after approval and implementation of these programs, the Company proposed to record related expenses in separate accounts. If applicable, separate accounts for residential and commercial programs would be maintained. Further, witness Paton explained that twice a year, at the same time that the Company files for a rate adjustment pursuant to the CUT, the Company would file for recovery of incurred program costs.

For purposes of settlement of this case, the Stipulating Parties agreed that PSNC should be allowed to recover $750,000 of conservation program expenditures incurred for its conservation initiatives through the cost of service instead of the rate tracker approach initially filed by the Company. The Stipulating Parties also agreed that PSNC should file the proposed programs for Commission approval within 30 days of the issuance date of the Order in this proceeding.

In this regard, the Stipulation provides as follows:

> 14. Conservation Program Expenditures. The Stipulating Parties agree that PSNC should be allowed to recover $750,000 of conservation program expenditures incurred for its conservation communications, in-home energy audit, energy efficient equipment rebate programs, and a high efficiency discount rate schedule proposal through the cost of service instead of the rate tracker approach initially filed by the Company. These conversation programs should be filed for approval within 30 days of the order in this proceeding and an annual report of expenditures detailing the funds spent on these programs should be filed by February 15th for each calendar year.

No party explicitly contested the proposed $750,000 annual level of conservation spending or recovery of conservation dollars as provided for in the Stipulation. In his Brief, the Attorney General stated that he supports the development of cost effective energy conservation programs. The Attorney General remarked that such programs have been funded through rates in other states and have produced substantial savings for many customers over time. The Attorney General recommended that, if the Commission approves the funding of energy conservation programs in PSNC's rates, then PSNC's efforts should be closely monitored given its lack of experience and the lack of detail in its proposals.

The Commission is of the opinion that, in general, energy conservation and energy efficiency measures serve the public interest and that measures such as weatherization should typically provide long-term and year-round benefits to PSNC's customers and to the public as a whole. The Commission finds that the Company's commitment to file programs of the nature described in this case for approval within 30 days of this Order and the strong public policy in support of promoting conservation warrants allowing the proposed $750,000 of expenditures for conservation programs to be included in the cost of service in this proceeding. Therefore, the Commission finds and concludes that these provisions are just and reasonable under the circumstances of this particular case and should be approved subject to the additional filing and reporting requirements discussed below. Consequently, consistent with the Stipulation, within 30 days following the issuance date of this Order, the Commission requires PSNC to file its specific program proposals for review and approval by the Commission. Such filing of PSNC's conservation programs should be made in accordance with Commission Rule R6-95,[1] where applicable, for any proposed programs. Additionally, the Commission believes that it is reasonable to require that the Company's soon-to-be-filed package of conservation proposals include one or more programs which offer an opportunity for all residential and commercial ratepayers to participate, if they so choose. Subsequent to PSNC's formal filing of its conservation program proposals, the Commission will provide an opportunity for interested parties to comment on such proposals. Thereafter, the Commission will review all filings on this matter and subsequently issue an order regarding the same.

Further, PSNC witness Paton testified that it will take a month or two after Commission approval to have its programs up and running. Consequently, the Commission finds and concludes that it is appropriate and reasonable to require that, to the extent the Company does not actually incur expenditures of $750,000 for its conservation programs in the first year, PSNC should be required to spend the remaining balance in the following year, in addition to the $750,000 for that next year.

In addition, consistent with the Stipulation, the Commission also requires that the Company file annual reports of expenditures detailing the funds spent on its conservation programs by February 15th for each calendar year. Furthermore, the Commission is of the opinion that these annual reports should provide detailed information for each program that will be beneficial in analyzing the effectiveness of having such programs in place, i.e., are such programs worthwhile and are the total costs of each program reasonable in light of the resulting benefits from the perspective of societal benefits and benefit-cost ratio analyses, where feasible; and should such programs be continued. Such reports should include relevant and useful information for each individual program such as (1) the purpose of program; (2) the duration of the program; (3) the classes of persons to whom the program is offered; (4) the number of participants; (5) the annual amounts for each element of costs incurred in connection with the program, e.g., labor, advertising, contracts, materials, equipment, direct payments, rebates, etc.; (6) the expected and achieved energy savings in total and average per customer; (7) the total dollar savings and average savings per customer; (8) any sources and amounts of funding from third parties and the reasons those parties are providing such funding; (9) a description of the tests used in evaluating cost effectiveness and any test results; (10) any proposed program modifications; and (11) any other pertinent information. The Commission encourages the Company, the Public Staff, and the Attorney General to engage in discussions, at their convenience, for the purpose of developing a consistent, relevant, and systematic reporting format to be followed by the Company in its annual reports, which should include the aforementioned information and other additional data and analyses used in performing and providing a proper and adequate evaluation of the effectiveness of PSNC's conservation programs.

[1] Rule R6-95 (Incentive programs for natural gas utilities) was adopted by Commission Order Adopting Final Rules, issued February 29, 2008, in Docket No. E-100, Sub 113. As used in Rule R6-95, "Program" means any natural gas utility action or planned action that involves offering "Consideration," as defined in said rule.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence for this finding is found in the Application; the direct testimony of Company witnesses Harris, Addison, Murry, Wright, and Paton; the Stipulation; the supplemental testimony of Company witness Paton; and testimony at the hearing.

With regard to the CUT, the Stipulation provides as follows:

> 9. Implementation of the Customer Usage Tracker and Elimination of Weather Normalization Adjustment Mechanism. The Stipulating Parties agree that it is appropriate to implement the Company's proposed customer usage tracker in the form of Rider C to the Company's tariffs, included in Exhibit E attached hereto, and designated as the "Customer Usage Tracker." The "R" values, baseload and heat sensitive factors to be used in the Company's Customer Usage Tracker in the future are set forth in Exhibit D attached hereto and incorporated by reference herein. As a consequence of the implementation of the Customer Usage Tracker mechanism, the Stipulating Parties further agree that it is appropriate to eliminate the Weather Normalization Adjustment mechanism in the Company's tariffs. Additionally, the stipulated return on common equity is lower than what the Company would otherwise have agreed to had the Stipulating Parties not agreed, among other considerations, to the implementation of the Customer Usage Tracker mechanism.

The proposed CUT addresses the issue of declining per customer usage of natural gas. While the number of customers continues to grow, the weather-normalized usage per residential customer continues to decrease due to improved appliance efficiency and better insulated homes and office buildings. Volatile natural gas prices have also caused customers to conserve. Company witnesses Wright and Harris testified that the Company has experienced a decline in usage per residential customer of approximately 2% per year over the last five years. Company witness Wright testified that, when PSNC has a rate case under the current regulatory model, the Company will not collect the approved revenues due to declining use per customer and that the CUT mechanism will adjust revenues to correspond to the volumes determined in this general rate case.

Company witness Paton testified that, because the proposed CUT mechanism will account for all variances in consumption, including those related to weather, the Company will no longer need the WNA. Additionally, Company witnesses Addison and Wright testified at the hearing to the disadvantages of the WNA.

At the hearing, the Company witnesses testified that, while the Company has added new customers, the growth in plant necessary to serve them has exceeded the revenues derived from those customers. Therefore, any decline in per-customer usage will not be offset by growth in the number of customers served. Company witnesses testified that, if per-customer natural gas consumption increases, the CUT adjustment will prevent the Company from recovering more than the margin set in this rate case. If per-customer usage continues to decline, even with the CUT mechanism, customers using less gas will have lower bills because the largest component of their bills is the cost of gas.

Based on the evidence as a whole, the Commission finds that it is appropriate to adopt the proposed CUT mechanism. Recently enacted legislation authorizes the Commission to approve a mechanism that tracks and trues-up gas utility rates for variations in average per-customer usage, upon making certain findings. G.S. 62-133.7 states, "The Commission may adopt a rate adjustment mechanism only upon a finding by the Commission that the mechanism is appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in the general rate case proceeding and that the mechanism is in the public interest." The Attorney General opposed PSNC's proposal to create such a rate mechanism. The Attorney General argued that the proposed CUT (1) is not in the public interest when viewed in the context of the policies in Chapter 62; and (2) is not appropriate, i.e., that it will not function to obtain the intended result.

With regard to the public interest, the Attorney General contended that the proposed CUT is overly broad as a tool for stabilizing revenues and that the benefits to the utility in terms of revenue stability and energy conservation incentives are not sufficient to offset the harm to consumers from frequent, unsupervised rate adjustments and upward pressure on rates. From the consumers' perspective, the CUT increases the variability of rates because it allows rate changes twice per year and does not limit the amount by which rates may increase. The Attorney General argued that the proposed CUT guarantees the utility full recovery of margin from residential and commercial customers without regard to volumes sold, thereby reducing shareholder risk and transferring considerable risk to customers. The Attorney General contended that, in order to be fair, consumers should realize a corresponding benefit, but no such benefit has been proposed. The Attorney General stated that, while the utility contended that the purpose of the CUT is to moderate revenues, the CUT will in fact grow revenues over time. With its customer base increasing, to the extent that the Company is shielded from the effect of declining per-customer consumption, its prospect for revenue growth is greatly enhanced. Further, the Attorney General argued that the proposed CUT is not tailored to encourage effective utility-sponsored energy conservation programs and that other incentives would likely be more effective and less costly.

In addition to a finding of the public interest, the Commission must also find that the proposed CUT is "appropriate" in order to approve it. The Attorney General argued that the Company has not shown that the CUT is designed appropriately because there is a "considerable delay" between deferral and recovery: most revenue deferrals are recorded during winter months, but the CUT would tend to increase rates at other times of the year, when natural gas is used for different purposes. The Attorney General contended that the proposed CUT does not provide sufficient safeguards when the semiannual rate adjustments are made: other factors that might affect the need for a rate adjustment are not examined and the scrutiny of proposed CUT adjustments is "cursory." Finally, if approved, the Attorney General argued that it would be advisable to limit the CUT mechanism to a period of years unless it is reauthorized in a future general rate case.

The Commission has considered the Attorney General's arguments against the proposed CUT and finds them unpersuasive. First, as testified to by PSNC witness Wright, the level of usage per customer established in a rate case is an assumption used to allocate revenue responsibility for the approved revenue requirement across a volumetric rate structure. This assumption inevitably turns out to be inaccurate in practice due to a variety of factors. Without the CUT, this inaccuracy benefits either the Company, if actual usage is greater than assumed usage, or the customers, if actual usage is lower than assumed usage. Under the CUT, both the Company and its customers know exactly how much margin the Company will collect from residential and commercial customers, which is the amount the Commission has determined to be reasonable.

Second, the proposed CUT tracks margin revenues against the Commission-approved margin levels and trues-up variations in margin recovery over time. The mechanism is bilateral in nature: it protects customers from an overcollection of margin revenues to the same degree that it protects the Company from an undercollection of margin revenues. In this manner, it protects against the possibility that the Company may receive a windfall between rate cases due to changes in residential and commercial customer usage. It is also clear from the evidence that the proposed CUT, in and of itself, will not cause the Company to overearn. The CUT will recover only PSNC's approved margin from residential and commercial customers.

Third, while the CUT works to avoid both overcollection and undercollection of margins revenues based on changes in residential and commercial customer usage, it is clear that there is a general trend toward reduced usage. PSNC witness Harris testified that, over the last five years, weather-normalized usage per residential customer has declined an average of 2% per year. PSNC witness Wright stated that the declining use per customer is expected to continue; that the Company's growth has largely been in the residential market; that new homes are better insulated; and that old homes are insulated as they are remodeled. He also stated that federal furnace and boiler efficiency standards have been increased. Finally, he testified that higher natural gas commodity prices have tended to result in customers increasing their conservation efforts. Company witness Harris testified that it has come to the point that declining usage is significantly limiting the Company's ability to earn a fair return. Witness Wright testified that the CUT more closely aligns the interests of the customer and the shareholder, as well as furthering the State's policy to promote conservation.

Growth on the Company's system is responsible for increases in margin revenues between rate cases, but this also occurred under traditional rate designs before the CUT. The Company is continuing to experience system growth as it has for many years, and such growth produces additional margin revenues. It is equally clear, however, that increased margin revenues do not automatically mean an increased return for the Company. When a utility adds customers, it also incurs additional costs to install and maintain facilities and otherwise support service to the additional customers. The additional margin revenues received for serving the new customers are an offset against the additional costs, but do not typically cause a utility to overearn its rate of return. In fact, PSNC witness Addison indicated that the addition of customers between rate cases typically erodes margin because the costs of serving new customers tend to be higher than the costs of serving existing customers. One of the advantages of the CUT is that any growth that adds margin revenues at a rate higher than that approved by the Commission in this case will actually lower rates for existing customers.

The Attorney General argued that customers receive no benefit from the CUT. However, in this rate case, PSNC witness Addison stated that the Company would not have accepted the return on equity in the Stipulation without a CUT, although he did not quantify the reduction that the Company accepted relating to the CUT. The Commission has testimony before it that the

Company agreed to give up a higher return on equity and higher monthly charges in exchange for the CUT. The Commission accepts this testimony, and so cannot agree with the Attorney General's assertion that customers will receive no benefit.

The Commission disagrees with the contention that the CUT will remove the Company's incentive to operate efficiently. PSNC witness Wright testified that, since the CUT does not address the level of expenses incurred, the Company must continue to operate efficiently in order to maintain profitability. Additionally, the Commission finds that the CUT is fair to customers. If per-customer natural gas consumption increases, the CUT adjustment will prevent the Company from recovering more than the margin set in this rate case. If per-customer usage declines, even with the CUT, customers using less gas will have lower bills because, as witnesses Wright and Addison stated, the largest component of the customers' bills is the cost of gas, and it is not subject to the CUT mechanism.

The CUT mechanism requires monthly reports to be filed showing activity in the CUT deferred accounts, requires 14 days notice to implement a rate adjustment under the CUT, and clearly provides that adjustments will be filed "for Commission approval." The Attorney General argues that such procedures are inadequate, that scrutiny will be "cursory," and that other factors will not be examined. The Commission requires that notice of the CUT mechanism explaining its purpose and workings shall be given to all affected customers following the issuance of this Order and to new customers and, thereafter, that notice of each increment or decrement approved as a result of the Company's semi-annual CUT rate adjustment filings shall be given with the first monthly bill reflecting the rate change. The Commission finds such to be adequate. The original public notice of this rate case proceeding ordered back in April 2008 gave notice that the CUT was proposed. The public has had notice and ample opportunity to weigh in on the policy considerations for and against the CUT. Once approved, the CUT adjustments will essentially be calculated and reviewed according to the mathematical formula set forth in the tariff. It is true, as argued by the Attorney General, that many factors will not be considered when the CUT adjustments are made, but that is inherent in the nature of the CUT mechanism. The CUT is not intended to operate as a mini-rate case in which all factors that might affect rates will be considered.

The Commission will not place any caps on the CUT. While it may be possible to design a capped CUT mechanism, there is no evidence in the record to support specific caps or explain how they would be designed or implemented or what effect they would have on ratepayers or the Company. Although the Attorney General referred to mechanisms in other states with such caps, he did not propose such a mechanism in this case. Further, adoption of a capped mechanism would maintain the adverse interests of the Company and its customers with respect to conservation. A major advantage of the CUT is that it neutralizes the Company's interest in maximizing customer usage. If a capped CUT mechanism were implemented, the Company would continue to have an interest in promoting customer usage because profits would increase if customers used more gas. Company-sponsored conservation programs would be at odds with the interests of the Company's shareholders since successful conservation programs would reduce usage and Company profits. For the reasons cited above, the Commission finds that a capped CUT mechanism should not be adopted.

Similarly, the Commission will not adopt the Attorney General's suggestion that the CUT, if authorized at all, be limited to a three-year life and terminated unless reauthorized in a future proceeding. The Commission has had some experience with a CUT mechanism by way of the three-year CUT experiment authorized for Piedmont in Docket No. G-9, Sub 499. While it is true that this experiment covered a truly extraordinary time and while it will be interesting to see how a CUT works in the future under what will presumably be very different conditions, the Commission, rather than prescribing a three-year life for the CUT, will instead simply note its authority to review and reconsider its orders. As with all orders, the Commission retains authority under the provisions of G.S. 62-80 to revisit the CUT mechanism, on its own motion or on the motion of a party, should circumstances justify such.

The Commission has carefully reviewed the evidence in this proceeding with regard to the question of whether the proposed CUT should be approved as agreed to by the Stipulating Parties. The Commission has carefully considered all of the Attorney General's arguments in light of the legal standard set forth by the General Assembly in G.S. 62-133.7. Based on this analysis, the Commission concludes that the CUT as stipulated is appropriate because it effectively operates as intended to decouple the Company's margin recovery from the usage patterns of its customers and that the mechanism is otherwise in the public interest because it stabilizes margin recovery for the Company and its customers; reduces risk to the Company and its customers arising from potential variations in usage patterns from multiple causes; facilitates the continued utilization of a volumetric rate structure; helps to preserve the Company's ability to recover its approved margin; ensures that the Company will not over-recover its approved margin; removes Company disincentives as to efficiency efforts and conservation programs; and reduces the need for the Company to make future rate filings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25 AND 26

The evidence supporting these findings is contained in the direct and supplemental testimony of Company witness Paton, the Stipulation, and Exhibits E and F attached thereto.

Company witness Paton testified to the proposed additional changes to the Company's tariffs and Rules and Regulations and the reasons underlying those changes. In general, witness Paton maintained that the changes are necessary and appropriate to reflect changes in market, usage, and regulatory conditions and to improve service.

The changes to the Company's tariffs and Rules and Regulations, which were agreed to among the Stipulating Parties, are reflected in Exhibits E and F to the Stipulation. No party objected to these changes except for the Attorney General, who objected to the implementation of the CUT mechanism as set forth in Rider C to the Company's tariffs. The Commission has carefully reviewed these changes to the Company's tariffs, including Rider C, as discussed in the Evidence and Conclusions for Finding of Fact No. 24, and to the Company's Rules and Regulations, and concludes that they are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

For the reasons set forth in the foregoing Evidence and Conclusions For Findings of Fact Nos. 1 - 26, the Commission concludes that the Stipulation in this proceeding provides a just and reasonable resolution of all the issues in this case; it will allow the Company a reasonable opportunity to earn a fair return; and it provides just and reasonable rates for all customer classes. The Commission finds and concludes that all of the provisions of the Stipulation, taken together, are just and reasonable under the circumstances of this proceeding and should be approved, subject to the additional filing and reporting requirements related to the conservation program process.

The following Schedule 1 summarizes the net operating income for return, rate base, and overall rate of return under present rates and approved rates as agreed to by the Stipulating Parties and as approved herein by the Commission. As reflected in Schedule 1, PSNC is granted an increase in its annual level of sales and transportation of revenues of $9,104,984 offset by $8,376,707 of reductions of fixed gas costs, for a net increase in rates and charges of $728,277, based upon the adjusted test-year level of operations approved herein.

SCHEDULE 1

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.
Docket No. G-5, Sub 495
STATEMENT OF NET OPERATING INCOME FOR RETURN, RATE BASE, AND OVERALL RATE OF RETURN
For the Test Period Ended December 31, 2007

Item	Per Company (a)	Adjustments (b)	After Adjustments (c)	Rate Increase (d)	After Rate Increase (e)
NET OPERATING INCOME FOR RETURN					
Operating Revenues:					
Sales and transportation of gas	$ 683,356,654	$ 39,506	$ 683,396,160	$728,277	$ 684,124,437
Other operating revenues	3,345,175		3,345,175		3,345,175
Operating revenues, excl special contracts	686,701,829	39,506	686,741,335	728,277	687,469,612
Special contract revenues	618,496		618,496		618,496
Total operating revenues	687,320,325	39,506	687,359,831	728,277	688,088,108
Cost of gas	476,879,986	(8,301,131)	468,578,855		468,578,855
Margin	210,440,339	8,340,637	218,780,976	728,277	219,509,253
Operating Expenses:					
Operating and maintenance	86,959,335	(267,579)	86,691,756	4,346	86,696,102
Depreciation	37,555,784	(385,068)	37,170,716		37,170,716
General taxes	9,344,474	(21,427)	9,323,047		9,323,047
State income tax (6.9%)	3,798,385	688,643	4,487,028	49,951	4,536,979
Federal income tax (35%)	17,937,733	3,252,082	21,189,815	235,893	21,425,708
Amortization of investment tax credits	(185,253)		(185,253)		(185,253)
Amortization of EDIT	(645,425)		(645,425)		(645,425)
Total operating expenses	154,765,033	3,266,651	158,031,684	290,190	158,321,874
Interest on customer deposits	(609,946)		(609,946)		(609,946)
Net Operating Income for Return	$ 55,065,360	$ 5,073,986	$ 60,139,346	$438,087	$ 60,577,433
RATE BASE					
Plant in service	$1,191,285,223	($12,647,033)	$1,178,638,190		$1,178,638,190
Accumulated depreciation	(427,817,811)	4,116,282	(423,701,529)		(423,701,529)
Net plant in service	763,467,412	(8,530,751)	754,936,661		754,936,661
Gas in storage	76,622,602	(2,725,017)	73,897,585		73,897,585
Materials & supplies	6,609,100	(16,269)	6,592,831		6,592,831
Other working capital	(20,192,106)	541,129	(19,650,977)		(19,650,977)
Deferred income taxes	(106,359,412)	249,175	(106,110,237)		(106,110,237)
Rounding adjustment		1	1		1
Original Cost Rate Base	$ 720,147,596	($10,481,732)	$ 709,665,864		$ 709,665,864
Overall Rate of Return on Rate Base	7.65%		8.47%		8.54%

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC is hereby authorized to adjust its rates and charges in accordance with the Stipulation in this proceeding (as such rates may be adjusted for any changes in the Benchmark Cost of Gas and changes in Demand and Storage Charges prior to the effective date of the revised rates) effective for service rendered on and after November 1, 2008.

2. That PSNC is hereby authorized to implement the tariffs attached to the Stipulation as Exhibit E effective November 1, 2008.

3. That PSNC is hereby authorized to implement the changes to the Rules and Regulations attached as Exhibit F to the Stipulation effective November 1, 2008.

4. That PSNC shall file tariff and Rules and Regulations to comply with this Order within ten days from the date of this Order.

5. That, in the true-up of fixed gas costs for periods subsequent to October 31, 2008, in proceedings under Rule R1-17(k), the Company shall use the fixed gas cost allocations set forth in Exhibit C to the Stipulation.

6. That the decoupling mechanism factors set forth on Exhibit D to the Stipulation are approved for use in the implementation of the provisions of that mechanism subsequent to October 31, 2008.

7. That PSNC shall file its specific conservation program proposals, and the amounts allocated to each such program for approval by the Commission, pursuant to Rule R6-95, within 30 days from the date of this Order. PSNC shall file annual reports accounting for its conservation program spending for the previous year on or before February 15th of each year. In addition, such annual reports shall include specific detailed information for each program that provides an analysis of the effectiveness of each program as discussed hereinabove. The first of these reports should be filed by February 15, 2010.

8. That, if PSNC does not incur $750,000 of expenditures for its conservation initiatives in the first year that the new rates are in effect, the Company shall spend that balance in the following year in addition to the $750,000 for that year.

9. That PSNC is hereby authorized to implement the other actions, practices, principles, and methods agreed upon in the Stipulation and not inconsistent with this Order.

10. That PSNC shall send the notice attached hereto as Appendix A to its customers beginning with the next billing cycle that includes the rate changes approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of October, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh102408.01

APPENDIX A
Page 1 of 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-5, SUB 495

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of	)	
North Carolina, Inc., for a General Increase	)	PUBLIC NOTICE
in its Rates and Charges	)	

The North Carolina Utilities Commission has issued an Order allowing Public Service Company of North Carolina, Inc. (PSNC or the Company), to increase its rates and charges by approximately $9.1 million annually, offset by an $8.4 million reduction in fixed gas costs, for a net increase of approximately $700,000. The overall increase of 0.11% is effective November 1, 2008.

On March 31, 2008, PSNC filed an application seeking a general increase in its rates and charges, approval of changes to its tariff and rate schedules, approval of a customer usage tracker mechanism applicable to its residential and commercial rate schedules, and approval of a cost recovery mechanism for customer conservation programs.

In its application, the Company requested an increase of approximately $20.4 million annually. The Company stated that the increase was needed to recover costs related to expanding and operating its pipeline system and the need to earn a fair and reasonable return on its investment. Since December 2005, PSNC has added more than 929 miles of transmission and distribution mains, installed over 41,000 new service lines, and has added more than 30,000 customers to its system.

The increase approved by the Commission was the result of a stipulation (Stipulation) entered into between the Company and other parties to the proceeding, including the Public Staff – North Carolina Utilities Commission. The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service. These approved increases are associated with allowed expenses and return on investment only and do not contemplate increases or decreases that may occur in association with gas cost adjustments to rates as allowed by G.S. 62-133.4.

APPENDIX A
Page 2 of 2

Overall, the Commission has approved a residential rate increase for the Company of 0.32%, although individual residential customers may experience larger or smaller percentage increases.

The Commission has approved a customer usage tracker mechanism, which will allow the Company to recover its approved margin independent of customer usage patterns. It will protect customers from the potential over-recovery of margin by the Company and will protect the Company from potential under-recovery of margin. The customer usage tracker mechanism will track margin recovery on a monthly basis and make semi-annual adjustments to usage rates to refund or recover differences from the Commission-approved margin level.

The Commission has also approved the annual expenditure of $750,000 on conservation programs to be recovered through rates and directed the Company to file its initial programs for approval by the Commission within 30 days from the date of the Commission's Order.

A list of approved rates effective November 1, 2008, can be obtained from the Company's website, www.psncenergy.com, or at the Office of the Chief Clerk of the Commission, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, where copies of the Commission's Order and the Stipulation are available for review by any interested party. The Commission's Order and the Stipulation, as well as other filings in these dockets can be viewed/printed from the Commission's website at www.ncuc.net using the Docket Search function.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of October, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

(SEAL)

DOCKET NO. G-9, SUB 550

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Piedmont Natural Gas	)	ORDER APPROVING PARTIAL RATE
Company, Inc., for a General Increase in its	)	INCREASE AND REQUIRING
Rates and Charges	)	CONSERVATION PROGRAM FILING
	)	AND REPORTING

HEARD IN: Chowan County Courthouse, Edenton, North Carolina, on July 14, 2008; Kinston City Hall, Kinston, North Carolina, on July 15, 2008; Judicial Building

Courtroom, Wilmington, North Carolina, on July 15, 2008; Burke County Courthouse, Morganton, North Carolina, on July 16, 2008; Mecklenburg County Courthouse, Charlotte, North Carolina, on July 17, 2008; High Point City Hall, High Point, North Carolina, on July 17, 2008; and the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina, on September 9, 2008

BEFORE: Commissioner William T. Culpepper, III, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Robert V. Owens, Jr.; Sam J. Ervin, IV; and Lorinzo L. Joyner

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 28202-4003

For the Using and Consuming Public:

Elizabeth Denning Szafran, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp, Page & Currin, LLP, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the United States Department of Defense:

Robert A. Ganton, Department of the Army, 901 N. Stuart Street, Suite 525, Arlington, Virginia 22203

BY THE COMMISSION: On February 29, 2008, Piedmont Natural Gas Company, Inc. (Piedmont or Company) gave notice pursuant to Commission Rule R1-17(a) of its intent to file a general rate case.

On March 10, 2008, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene. On March 11, 2008, the Commission issued an Order granting the petition to intervene of CUCA. On March 12, 2008, the Attorney General filed its Notice of Intervention. On March 28, 2008, the U.S. Department of Defense (DOD) filed a Petition to Intervene. On April 2, 2008, the Commission issued an Order granting the petition to intervene of the DOD.

On March 31, 2008, Piedmont filed a petition (Petition or Application) seeking an increase in and revisions to its rates and charges, approval of changes to its rate design, rate schedules and practices, permanent extension of its margin decoupling mechanism, and approval of conservation and energy efficiency programs and recovery of associated costs. The Company also filed the direct testimony and exhibits of Thomas E. Skains, Chairman, President and Chief Executive Officer of Piedmont; David J. Dzuricky, Senior Vice President and Chief Financial Officer of Piedmont; Frank H. Yoho, Senior Vice President of Commercial Operations of Piedmont; David R. Carpenter, Managing Director of Regulatory Affairs of Piedmont; William C. Williams, Managing Director of Transportation and Major Account Services of Piedmont; Russell A. Feingold, Vice President, Rate & Regulatory Group, Enterprise Management Solutions Division, Black & Veatch Corporation; Dr. Donald A. Murry, Vice President and Economist with C. H. Guernsey & Company; Paul M. Normand, President and Management Consultant, Management Applications Consulting, Inc.; and Gary L. Goble, Managing Consultant, Management Applications Consulting, Inc. On April 4, 2008, Piedmont filed an amendment to its Petition providing a page intended to be attached to the testimony of Company witness Williams that was inadvertently omitted from the original filing.

By Order issued April 30, 2008, the Commission declared the Company's application to be a general rate case pursuant to G.S. 62-137 and suspended the proposed rates for a period of up to 270 days from and after May 1, 2008. In that Order, the Commission also set the matter for hearing, required the Company to give notice of the hearing, established discovery guidelines, and established dates for interventions and for the prefiling of direct testimony by intervenors and for the prefiling of rebuttal testimony by the Company.

On May 15, 2008, Hess Corporation (Hess) filed a Petition to Intervene. On May 20, 2008, the Commission issued an Order granting Hess' petition to intervene. On July 14, 2008, Texican Horizon Energy Marketing, LLC (Texican) filed a Petition to Intervene. On July 16, 2008, the Commission issued an Order granting Texican's petition to intervene.

On July 14, 2008, the matter came on for hearing in Edenton as scheduled. No person appeared to testify as a public witness. On July 15, 2008, the hearing was continued in Kinston as scheduled. No person appeared to testify as a public witness. Also on July 15, 2008, the hearing was continued in Wilmington as scheduled. No person appeared to testify as a public witness. On July 16, 2008, the hearing was continued in Morganton as scheduled. At the hearing in Morganton, Ms. Sandra Bristol testified as a public witness. On July 17, 2008, the hearing was continued in Charlotte as scheduled. No person appeared to testify as a public witness. Also on July 17, 2008, the hearing was continued in High Point as scheduled, at which time the following public witnesses testified: Mr. James Curtis and Mr. William Gay.

On August 22, 2008, the DOD prefiled the direct testimony of Kenneth L. Kincel. On August 25, 2008, the Attorney General's Office prefiled the direct testimony and exhibits of Roger D. Colton.

On August 25, 2008, the Company, the Public Staff, CUCA, DOD, and Texican (Stipulating Parties) filed a stipulation (Stipulation) resolving all issues in this proceeding between the Stipulating Parties.

On September 2, 2008, the Company filed the supplemental testimony and exhibit of David R. Carpenter. On September 4, 2008, the DOD filed a motion to withdraw its prefiled direct testimony of Kenneth L. Kincel. The DOD's motion was granted by Commission Order issued on September 9, 2008.

On September 9, 2008, the hearing in Raleigh was held as scheduled. No public witnesses appeared. At the hearing, the Company reported, and the Stipulating Parties confirmed, that, following substantial negotiations, a comprehensive agreement had been reached between the Company, the Public Staff, CUCA, DOD, and Texican and that this agreement resolved all issues in the case between those parties, and that this agreement was reflected in the Stipulation. Counsel for the Company further reported that following conversations with counsel for Hess, he was authorized to report that Hess did not intend to take an active role or position in the case.

At the hearing, the various prefiled direct and supplemental testimony and exhibits of the following witnesses were offered and accepted into evidence: Thomas E. Skains, David J. Dzuricky, Frank H. Yoho, David R. Carpenter, William C. Williams, Dr. Donald A. Murry, Russell A. Feingold, Paul M. Normand, Gary L. Goble, and Roger D. Colton. Company witnesses Carpenter, Dzuricky, and Yoho testified at the hearing as a panel and answered questions from the Attorney General and the Commission.

On September 25, 2008, Piedmont filed late-filed exhibits and other supplemental information as directed by the Commission at the hearing of this matter. Piedmont also filed, for informational purposes, descriptions of the conservation programs it intends to file for approval by the Commission if the Stipulation is approved. This additional information has not been agreed upon by the Stipulating Parties, but was provided to the Commission as an indication of conservation programs the Company intends to pursue.

On October 2, 2008, the Joint Proposed Order of Piedmont and the Public Staff was filed. Also, on October 2, 2008, the Attorney General filed his Brief.

Based upon the verified Petition; the testimony and exhibits received into evidence at the hearings; the Stipulation; and the entire record in this proceeding, the Commission now 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 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 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. 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 its Petition in this docket, Piedmont is seeking approval of: (a) a general increase in and revisions to the rates and charges for customers served by the Company; (b) certain changes to the cost allocation, rate designs, and practices underlying existing rates for the Company; (c) changes to the Company's existing service regulations and tariffs; (d) extension, on a permanent basis, of its margin decoupling mechanism; (e) conservation and energy efficiency program funding and recovery of the costs thereof; and (f) proposed funding of gas distribution research and development activities conducted by the Gas Technology Institute (GTI).

5. The Piedmont is properly before the Commission with respect to the relief sought in its Petition pursuant to the provisions of Chapter 62 of the General Statutes of North Carolina.

6. The only parties submitting evidence in this case with respect to revenues, expenses, and rate base levels used a test period consisting of the 12 months ended December 31, 2007, adjusted for certain known and measurable changes through June 30, 2008, or thereafter, and the Stipulation was based upon the same test period.

7. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2007, updated for certain known and measurable changes through June 30, 2008, or thereafter.

8. The Stipulation executed by Piedmont, the Public Staff, CUCA, DOD, and Texican, is supported or not opposed by all parties to this docket with the exception of the Attorney General.

9. The Stipulation settles all matters in this docket as to all parties except for the matters raised by the Attorney General.

10. In its Petition in this docket, the Company sought an increase in annual revenues of $40,516,128.

11. The Stipulation provides for an increase in annual revenues for Piedmont of $15,680,742, as set forth in Paragraph 6.F. This provision is just and reasonable and should be approved.

12. The Stipulating Parties agreed that the appropriate level of original cost of utility property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the Company's customers within North Carolina is $1,255,671,912, consisting of gas plant in service of $2,058,393,497, working capital of $133,242,468 and unamortized debt redemption premium of $94,008 reduced by accumulated depreciation of $740,345,517, customer advances for construction of $289,734, and accumulated deferred income taxes of $195,422,809, as described and set forth in Paragraph 5

and Exhibit A of the Stipulation. These provisions are just and reasonable and should be approved.

13. The Stipulating Parties agreed that the Company's end-of-period pro forma revenues under present rates for use in this proceeding are $1,050,244,526, consisting of $1,014,958,963 of sales and transportation revenues, $30,689,548 of special contract revenues, and $4,596,015 of other operating revenues, as described and set forth in Paragraph 6.A and Exhibit A of the Stipulation and that the pro forma annual operating revenues under the agreed-upon rates are $1,065,925,268, as set forth in Paragraph 6.F. and Exhibit A of the Stipulation. These provisions are just and reasonable and should be approved.

14. The Stipulation provides that the Company's operating expenses, including actual investment currently consumed through reasonable actual depreciation, are $266,078,482, as set forth in Paragraph 6.B and Exhibit A. This provision is just and reasonable and should be approved.

15. The Stipulating Parties agreed that the overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property, as described in Finding of Fact No. 12, is 8.55% as set forth in Paragraph 6.E and Exhibit A of the Stipulation, which includes a return on common equity of 10.60%, as set forth in Revised Paragraph 6.D of the Stipulation. Further, the Stipulating Parties agreed that the appropriate capital structure consists of 51% common equity, 6% short-term debt, and 43% long-term debt, with the cost of short-term debt and long-term debt being 3.05% and 6.89%, respectively, as set forth in Revised Paragraph 6.C of the Stipulation. These provisions are just and reasonable and should be approved.

16. The Stipulation provides that, for purposes of this proceeding, the appropriate level of adjusted sales and transportation volumes is 116,123,366 dekatherms (dts), which is comprised of 72,557,299 dts of sales quantities and 43,566,067 dts of transportation quantities, as described and set forth in Paragraph 3.A of the Stipulation. The Stipulating Parties agreed that the appropriate level for company use and lost and unaccounted for gas is 2,206,344 dts and that the appropriate level of purchased gas supply is 74,763,643 dts, consisting of sales volumes, company use gas, and lost and unaccounted for gas, as described and set forth in Paragraphs 3.B and 3.C, respectively, of the Stipulation. These provisions are just and reasonable and should be approved.

17. The Stipulating Parties agreed that the fixed gas costs that should be embedded in the stipulated rates and used in true-ups of fixed gas costs for periods subsequent to November 1, 2008, in proceedings under Rule R1-17(k) are those derived from the fixed gas cost allocation percentages set forth in Exhibit C to the Stipulation. This provision is just and reasonable and should be approved.

18. The agreed-upon rate design and rates, including volumetric rates, fixed monthly charges, demand charges, and other charges, as described in Paragraph 7 of the Stipulation and reflected in the column shown as "Proposed Rates ($/DT)" on Revised Exhibit B of the Stipulation (as the same may be adjusted for any changes in the Company's Benchmark Cost of

Gas or changes in demand and storage charges prior to the effective date of the revised rates), are just and reasonable and should be approved.

19. The Stipulating Parties agreed that the reasonable level for the total cost of gas in this proceeding is $685,026,672, as described in Paragraph 4.B and on Exhibit G to the Stipulation. This provision is just and reasonable and should be approved.

20. The agreed-upon treatment of margin from the City of Monroe, as described in Paragraph 14 of the Stipulation, is just and reasonable and should be approved.

21. The Stipulation provides for the amortization of pipeline integrity management costs and EasternNC deferred operations and maintenance expenses as set forth and described in Paragraph 10 of the Stipulation. This provision is just and reasonable and should be approved.

22. The Stipulation provides that Piedmont will file its proposed conservation programs for approval within 45 days of this Order and that Piedmont will be allowed to recover $1,275,000 of conservation program expenditures through the cost of service in this proceeding, as set forth in Paragraph 13 of the Stipulation. This provision is just and reasonable and should be approved subject to the additional filing and reporting requirements as set forth hereinafter.

23. The Stipulating Parties agreed that the funding of research and development activities through annual payments to the GTI of $250,000 per year, which is included in the overall level of test year operating expenses, as described in Paragraph 6.B of the Stipulation and as set forth on Exhibit A attached thereto, is just and reasonable and should be approved.

24. The Margin Decoupling Tracker (MDT), previously referred to as the Customer Utilization Tracker (CUT), as described in Paragraph 9 and as set forth as Appendix C to Exhibit F of the Stipulation, and the associated margin decoupling mechanism factors, as set forth in Exhibit D to the Stipulation, are appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in this rate case proceeding. The mechanism is in the public interest and should be approved.

25. The agreed-upon tariffs, attached to the Stipulation as Exhibit E, are just and reasonable and should be approved.

26. The agreed-upon Service Regulations, which are reflected in Exhibit F to the Stipulation, are just and reasonable and should be approved, with one minor modification. The Commission's web site address should be referenced as www.ncuc.net.

27. The Stipulating Parties agreed that the overall rate of return approved by the Commission in this proceeding should be used by the Company as its Allowance for Funds Used During Construction (AFUDC) rate. This provision is just and reasonable and should be approved.

28. All of the provisions of the Stipulation are just and reasonable under the circumstances of this proceeding and should be approved, subject to the additional filing and reporting requirements related to the conservation program process as set forth hereinafter.

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

The evidence supporting these findings is contained in the Company's verified Petition; the testimony and exhibits of the various witnesses; the NCUC Form G-1 that was filed with the Application; the provisions of Chapter 62 of the General Statutes; and the Commission's records as a whole. These findings are primarily jurisdictional and informational and are not contested by any party.

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

The Company filed its Application and exhibits using a test period consisting of the 12 months ended December 31, 2007. In its April 30, 2008 Order in this docket, the Commission required the parties to use a test period consisting of the 12 months ended December 31, 2007, with appropriate adjustments. The Stipulation is based upon the test period ordered by the Commission, and this test period was not contested by any party. In the Stipulation, the Stipulating Parties agreed to make appropriate adjustments to the test period data for circumstances occurring or becoming known through June 30, 2008, or thereafter. These adjustments were not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 9

These findings are supported by the Stipulation and by representations of counsel for the Stipulating Parties at the hearing of this matter.

The Stipulation recites that it was filed on behalf of Piedmont, the Public Staff, CUCA, the DOD, and Texican. The Stipulation provides that it represents a complete and integrated settlement of all matters at issue between the Stipulating Parties in this proceeding. At the hearing of this matter, counsel for each of these parties except Texican (who was not present) indicated that they supported the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 - 11

These findings are supported by the Petition; the direct testimony and exhibits of Company witness Dzuricky; the direct and supplemental testimony and exhibits of Company witness Carpenter; and the Stipulation. Schedule 7 to Exhibit (DJD-1) indicates that the Company filed for a revenue increase of $40,516,128 in this proceeding. The Stipulation, in Paragraph 6.F, indicates that, pursuant to the agreement of the Stipulating Parties, the Company should be allowed to increase its revenues by $15,680,742. This increase in revenues is further reflected in the supplemental testimony of Company witness Carpenter and Supplemental Exhibit (DRC-1). These findings are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The reasonable original cost of the Company's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas utility service to the public within North Carolina, less that portion of the cost that has been consumed by depreciation expense, is described and set forth in Paragraph 5 and Exhibit A to the Stipulation and reflected on Schedule 1 included herein.

The amounts provided on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and the supplemental testimony of Company witness Carpenter, and are not opposed by any party. The stipulated reasonable original cost of the Company's property used and useful, or to be used and useful within a reasonable time after the test period, in providing natural gas service to the public, less depreciation expense, is not contested by any party. The Commission has carefully reviewed these amounts, as well as all the record evidence relating to the Company's rate base, and concludes that the stipulated amounts are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The end-of-period pro forma revenues under the Company's present and stipulated rates are set forth in Paragraph 6 and Exhibit A to the Stipulation and reflected on Schedule 1 included herein.

The amounts included on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and the supplemental testimony of Company witness Carpenter. The stipulated pro forma revenues of the Company are not contested by any party. The Commission has carefully reviewed these amounts, as well as all record evidence relating to pro forma revenues, and concludes that the stipulated pro forma revenues are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The Company's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are set forth in Paragraph 6 and Exhibit A to the Stipulation and reflected on Schedule 1 included herein. The amounts included on Exhibit A to the Stipulation are the result of negotiations among the Stipulating Parties in this docket, as described in the Stipulation and the supplemental testimony of Company witness Carpenter. The stipulated, reasonable operating expenses of the Company are not contested by any party. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the Company's reasonable operating expenses, and concludes that the stipulated, reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding is contained in the Company's Application; in the testimony of Company witnesses Dzuricky and Carpenter; and in the Stipulation.

The overall rate of return on the cost of the Company's used and useful property is 8.55%, as set forth in Paragraph 6 and Exhibit A to the Stipulation and reflected on Schedule I included herein. As set forth in Paragraph 6, the overall rate of return reflects a capital structure consisting of 51.00% common equity; 43.00% long-term debt at a cost of 6.89%; and 6.00% short-term debt at a cost of 3.05%. The allowed rate of return on common equity is 10.60%. The overall cost of capital and its components are the result of negotiations among the Stipulating Parties. The stipulated return, debt costs, and capital structure vary in several respects from that filed by the Company in its Application. In the Company's Application, the proposed capital structure consisted of 43.97% long-term debt at a cost of 6.91%; 6.45% short-term debt at a cost of 2.77%; and 49.59% common equity at a return of 12.00%. The overall rate of return on the Company's used and useful property contained in the Company's Application was 9.17%. On a comparative basis, the stipulated capital structure slightly reduces the cost and size of the long-term debt component; slightly reduces the size of the short-term debt component; slightly increases the cost of short-term debt; slightly increases the common equity component; and significantly reduces the allowed return on common equity and overall rate of return. A comparison of witness Dzuricky's Exhibit (DJD-1) and the Stipulation and witness Dzuricky's testimony at the hearing reveals that the overall rate of return and return on common equity are substantially lower under the Stipulation than under the request made in Piedmont's initial filing. Similarly, as testified to by Company witness Dzuricky at the hearing, they are lower than the current rates of return embedded in Piedmont's rates. Further, as reflected in Company witness Carpenter's supplemental testimony, the net result of the adjustments in capital structure reflected in the Stipulation is a decrease in Piedmont's revenue requirement of more than $12 million.

At the hearing of this matter, Company witness Dzuricky testified, on cross-examination, that the stipulated allowed rate of return on common equity was in the range of allowed rates of return for other natural gas companies reported by the Commission in its quarterly monitoring report for the quarter ending December 31, 2007, and that it was reasonable for use in this proceeding. Witness Dzuricky further testified that the various components of Piedmont's capital structure vary over time and do not remain constant and that, while the stipulated equity component of 51.00% was the product of negotiations, it was well within the range of historical experience of the Company; within the range of reason for natural gas distribution companies; and also within the target equity range established by the Company of 50-55% common equity as published in Piedmont's most recent annual Form 10-K report.

The Commission has carefully reviewed the record evidence relating to the stipulated capital structure, return on common equity, and overall rate of return and concludes that the stipulated overall rate of return is just and reasonable. Said return will allow the Company, by sound management, the opportunity to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they now exist; to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise; and to compete in the market for capital funds on terms which are reasonable and fair to its customers and to its existing investors.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The level of adjusted sales and transportation volumes used in the Stipulation is 116,123,366 dts and the level of purchased gas supply is 74,763,643 dts. The throughput volume level is derived as follows:

Item	Amount (dts)
Sales	72,557,299
Transportation	43,566,067
Total Throughput	116,123,366

The level of purchased gas supply is 74,763,643 dts derived as follows:

Item	Amount (dts)
Sales	72,557,299
Company Use and Lost & Unaccounted For	2,206,344
Purchased Gas Supply	74,763,643

This throughput level and level of purchased gas supply are the result of negotiations among the Stipulating Parties, as described and set forth in Paragraph 3 of the Stipulation and in the supplemental testimony of Company witness Carpenter, and are not opposed by any party. The Commission has carefully reviewed this throughput level and concludes that it is a just and reasonable approximation of the Company's pro forma adjusted sales and transportation volumes. The Commission has also carefully reviewed the purchased gas supply level and concludes that it is a just and reasonable approximation of the Company's pro forma purchased gas supply level.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

Under the Commission's procedures for truing-up fixed gas costs in proceedings under Rule R1-17(k), it is necessary and appropriate to determine the amount of fixed gas costs that are embedded in the rates approved herein. In Paragraph 8 of the Stipulation, the Stipulating Parties agreed that, for the purpose of this proceeding and future proceedings under Rule R1-17(k) during the effective period of rates approved in this proceeding, the appropriate amount of fixed gas costs to be allocated to each rate schedule is as set forth in Exhibit C to the Stipulation. No party contested this allocation. The Commission has carefully examined these amounts, as well as all record evidence on fixed gas cost allocations, and concludes that the stipulated allocations of fixed gas costs are just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding is contained in the Stipulation; in the Company's Application; and in the testimony of Attorney General witness Colton and Company witness Carpenter.

The computation of revenues under the proposed rates (based on an $8.00 wholesale Benchmark Cost of Gas) is set forth on Revised Exhibit B of the Stipulation. These computations show that the proposed rates will produce the revenues calculated under the rate design approved for use in this proceeding.

In its Application, the Company proposed a secondary alternative rate design involving a substantial increase to the fixed monthly facilities charges applicable to residential and commercial customers. According to Company witness Carpenter, the purpose of this proposed increase was to recover a greater percentage of the Company's fixed costs through fixed charges if the Company's proposal to continue its CUT/MDT mechanism was not approved.

In his direct testimony, Attorney General witness Colton opposed the alternative proposal to increase fixed monthly charges for residential customers and presented a variety of arguments and analyses that tended to suggest that increased fixed monthly charges for residential customers have a disproportionate impact on low income and elderly customers. Based on this conclusion, witness Colton opposed any increase in the monthly facilities charges for residential customers, favoring, instead, a continuation of Piedmont's primarily volumetric rate structure.

As a result of the Stipulation in this proceeding, the Stipulating Parties have agreed to continue Piedmont's CUT/MDT mechanism instead of adopting Piedmont's secondary alternative rate design. Instead, the Stipulating Parties have agreed to maintain the existing level of fixed monthly charges for residential customers in Piedmont's rate design. Sustaining the existing level of fixed monthly charges for residential customers is consistent with witness Colton's testimony; is supported by the Stipulating Parties; and is not opposed by any party. The Commission concludes that the facilities charges reflected in the Stipulation are appropriate in this proceeding and should be approved.

With respect to the rate design as a whole, the Stipulation reflects the agreement of the Stipulating Parties, who collectively represent the major segments of Piedmont's customer base potentially impacted by this rate proceeding, that these rates are proper, just, and reasonable. According to Company witness Carpenter, the stipulated rate design was the result of negotiations between the Stipulating Parties and was accepted as reasonable by each of these parties. As reflected in Revised Exhibit H to the Stipulation and Piedmont Redirect Exhibit No. 1, the rate increase and calculated return for each class of customers served by Piedmont resulting from the stipulated rate design is relatively modest and well within the range of reason. This conclusion is uncontested and no other party presented evidence on this issue. The Commission has carefully reviewed these rates, as well as all record evidence relating to the proper rates to be implemented in this proceeding, and concludes that the stipulated rates are just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding is contained in the Company's initial filing, the Stipulation and the supplemental testimony of Company witness Carpenter.

The test period cost of gas is set forth in Paragraph 4 and Exhibit G to the Stipulation. The amounts shown on Exhibit G to the Stipulation are the result of negotiations among the Stipulating Parties in this docket. As described in the Stipulation and in the supplemental testimony of Company witness Carpenter, the fixed gas cost component of the cost of gas reflects the currently effective pipeline transportation and storage rates and an ongoing level of credits from secondary market transactions. Company witness Carpenter explained that, while the Company has typically updated its fixed gas costs in prior rate proceedings, automatically taking that step without factoring in the impact of secondary market activity credits often results in an overcollection of gas costs that must then be returned to customers over a period of 12 months in an annual gas cost review proceeding. Taking secondary market credits into account in establishing gas costs in this proceeding effectively gives customers immediate credit for these amounts. Inasmuch as the fixed gas cost component of Piedmont's rates can be adjusted, if necessary, to account for significant changes in those costs between rate cases under Commission Rule R1-17, the Commission perceives no danger to the Company and some advantages to customers from adopting this methodology for purposes of the present proceeding.

The stipulated cost of gas was not contested by any party to this proceeding. The Commission has carefully reviewed these amounts, as well as all record evidence relating to the pro forma cost of gas, and concludes that the stipulated cost of gas is reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The Stipulating Parties agreed, as set forth in Paragraph 14 of the Stipulation, that the volumes attributable to the City of Monroe should be included in Piedmont's volumetric throughput and margin contribution for purposes of determining rates herein, but that, upon any departure by Monroe from Piedmont's system following approval of this Stipulation, Piedmont should be entitled to record the resulting margin losses in its All Customers Deferred Account pending the establishment of new rates in Piedmont's next general rate case. In this regard, the Stipulation provides as follows:

> 14. Special Contracts Margins. In its filing, the Company proposed to eliminate volumes associated with the City of Monroe from its throughput in anticipation of Monroe's departure from Piedmont's system and to credit any revenues received from Monroe to its customers in the interim. The Stipulating Parties agree that it is appropriate to include volumes attributable to Monroe in Piedmont's throughput for purposes of establishing rates herein but that upon any departure by Monroe from Piedmont's system following approval of this Stipulation, Piedmont shall be entitled to record the resulting margin losses in its all Customers Deferred Account pending the establishment of new rates in Piedmont's next general rate case.

Such provision provides interim protection to Piedmont in the event of a termination of service to the City of Monroe as a result of the bypass pipeline Monroe is currently pursuing. The Company had initially proposed to exclude volumes attributable to Monroe from its rate structure and to credit revenues received by Monroe to its gas cost deferred accounts pending Monroe's abandonment of service. The underlying premise of the Company's proposal was the assumption that Monroe was no longer a Piedmont customer. The Stipulation takes a different approach and assumes that Monroe is a continuing customer of Piedmont so that Monroe's revenues and volumes are included in the stipulated cost of service and rate design. This is reflective of current reality, and the Commission finds it to be a rational approach to handling revenues and rates with respect to Piedmont's continuing service to Monroe. By the same token, the Stipulation provides some protection to Piedmont in the event that Monroe does actually complete its bypass pipeline and abandon service from Piedmont. That protection is the ability of Piedmont to record margin losses associated with such abandonment, if it occurs, in the Company's deferred accounts. Without this mechanism, Monroe's bypass could trigger an immediate rate filing by Piedmont. No party contested this provision of the Stipulation.

The Commission notes that the reasonableness of costs recorded in the All Customers Deferred Account and whether or not those costs were prudently incurred are reviewed by the Commission in an annual proceeding[1]. Nothing in this Order should be construed as prejudging the reasonableness and prudence of costs associated with Piedmont's service to the City of Monroe or the treatment of such costs in the event that Piedmont loses Monroe as a customer.

The Commission has carefully examined the agreed-upon treatment of margin related to the City of Monroe and concludes that the stipulated treatment is a rational means to address a material uncertainty in the reliability of margin recovery from a substantial customer on Piedmont's system. Consequently, the Commission finds and concludes that such treatment is just and reasonable to the Company and its ratepayers. Further, consistent with long-standing, well-established Commission policy and practice, the Commission concludes that the ultimate recoverability of margin losses placed in the All Customers Deferred Account arising from any departure by the City of Monroe from Piedmont's system, if such an eventuality should occur, shall be contingent upon the Commission's finding in a future proceeding that such costs are reasonable and that they were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding is contained in the Company's initial filing; the Stipulation; and the supplemental testimony of Company witness Carpenter.

The Stipulation provides certain agreed-upon amortizations relating to the recovery of unrecovered deferred costs, as described and set forth in Paragraph 10 of the Stipulation, associated with the following deferred regulatory assets established pursuant to previous Commission Orders: (a) Pipeline Integrity Management (PIM) costs and (b) EasternNC deferred

[1] In more recent years, utilities have usually requested modification to rate riders associated with the All Customers Deferred Account in conjunction with the Commission's annual prudence review of their natural gas costs pursuant to the provisions of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6). However, utilities may petition the Commission for such changes at any time.

operations and maintenance (O&M) expenses. The PIM costs are subject to amortization over a three-year period and represent costs accumulated by the Company between July 1, 2005 and June 30, 2008. The EasternNC deferred O&M expense subject to amortization is the October 31, 2008 unamortized balance of $9,302,411. The Stipulating Parties agreed that it is appropriate for the Commission to allow the Company to amortize and recover this unamortized balance over a 12-year period on a levelized basis that includes the accrual of interest at the net-of-tax overall rate of return. The Stipulating Parties further agreed to continue the existing regulatory asset treatment for ongoing PIM costs until an appropriate recovery mechanism is established in a future proceeding. The Stipulating Parties support the amortization periods set forth in Paragraph 10 of the Stipulation and the ongoing interim deferral mechanism for PIM costs. No party opposed the agreed-upon accounting treatment contained in Paragraph 10 of the Stipulation.

The Commission has carefully considered the agreed-upon amortization periods and related matters set forth in Paragraph 10 of the Stipulation, as well as all record evidence on the amortization of these regulatory assets, and concludes that the stipulated amortization periods are just and reasonable and should be approved. The Commission further concludes that the proposed continuation of the existing regulatory asset treatment for ongoing PIM costs is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence for this finding is found in Piedmont's Application; the prefiled testimony of Company witness Yoho; the Stipulation; the supplemental testimony of witness Carpenter; the testimony at the hearing; and Piedmont's supplemental information and late-filed exhibits filed on September 25, 2008.

In its Application, Piedmont proposed to spend and recover through rates $3,000,000, annually, for the promotion of energy conservation and energy efficiency measures. The Company's proposal did not include any conservation or efficiency efforts that would offer incentives or rebates for customers to change or upgrade energy appliances or equipment, as it is Piedmont's belief that energy efficiency programs promoting high-efficiency appliances and equipment should be evaluated and implemented on a multifuel, total fuel-cycle efficiency basis. Piedmont witness Yoho asserted that such an approach should be used in analyzing any incentive or efficiency programs that have the potential to displace competing energy services (electricity versus natural gas). Witness Yoho explained the allocation of the $3,000,000, among the various programs, stating that

> Initially, this funding would be allocated as follows: (1) $1 million annually to low income residential weatherization efforts administered by community groups already engaged in weatherization programs for low income customers; (2) $1 million annually to fund weatherization programs for non-profit entities; (3) $700,000 annually to Advanced Energy to fund infrastructure development efforts for weatherization contractors; and (4) $300,000 annually to promote customer conservation through public service communications and messages.

Further, witness Yoho testified that the continuation of Piedmont's volumetric rate structure with the margin decoupling mechanism would remove disincentives to promoting conservation that may exist in utility rate structures and that a provision for the recovery of program costs through rates would allow the Company to promote prudent programs that help achieve desirable conservation efforts. Witness Yoho maintained that it is imperative that Piedmont's margin recovery be protected through the margin decoupling mechanism; otherwise, Piedmont would be "disincented" to engage in the active ongoing promotion of reduced usage of natural gas by its customers through conservation and efficiency measures because of the substantial risk such actions would pose to the Company and its shareholders.

For purposes of settlement of this case, the Stipulating Parties agreed that Piedmont should be allowed to recover $1,275,000 of conservation program expenditures incurred for its conservation initiatives through the cost of service. The Stipulating Parties also agreed that Piedmont should file the proposed programs for Commission approval within 45 days of the issuance date of the Order in this proceeding.

In this regard, the Stipulation provides as follows:

> 13. Conservation Programs and Cost Recovery. The Stipulating Parties agree that the Company's proposal to provide conservation programs should be approved and that the costs thereof, equal to $1,275,000 per fiscal year should be included in the Company's annual operating revenues. The Company shall file its specific program proposals for approval by the Commission within forty five (45) days following the issuance of a Commission order approving this Stipulation. The Company shall file, for informational purposes, an accounting of its conservation program spending for the previous year on or before June 15th of each year. The first of these reports shall be filed by June 15, 2009.

No party explicitly contested the proposed $1,275,000 annual level of conservation spending or recovery of conservation dollars as provided for in the Stipulation. In his Brief, the Attorney General stated that he supports the development of cost effective energy conservation programs. The Attorney General remarked that such programs have been funded through rates in other states and have produced substantial savings for many customers over time. The Attorney General recommended that, if the Commission approves the funding of energy conservation programs in Piedmont's rates, then Piedmont's efforts should be closely monitored given the Company's experience during the CUT experiment.

Further, on September 25, 2008, Piedmont provided late-filed exhibits and other supplemental information, as directed by the Commission at the hearing. In that supplemental filing, Piedmont included, for informational purposes, a description of the two conservation programs it intends to file for approval by the Commission if the Stipulation is approved. In particular, Piedmont indicated that it plans to propose that the annual funding of $1,275,000 for conservation and energy efficiency programs be allocated as follows: (1) $775,000 annually to fund home weatherization for low-income residential customers in Piedmont's service territory, and (2) $500,000 annually to fund weatherization of facilities operated by nonprofit charitable entities who are currently Piedmont's customers. However, Piedmont stated that this additional information was provided to the Commission to indicate the conservation programs that it intends to propose, but Piedmont observed that these proposals have not been addressed nor agreed to by the Stipulating Parties. Additionally, in the Joint Proposed Order of Piedmont and the Public Staff, in their discussion regarding Piedmont's September 25, 2008 supplemental filing, they state that "the Company indicated its intent to file to expend these funds on just two conservation programs for the first year following approval of the Stipulation." Thus, the Commission surmises that Piedmont will likely propose some additional or replacement programs in subsequent years.

The Commission is of the opinion that, in general, energy conservation and energy efficiency measures serve the public interest and that measures such as weatherization should typically provide long-term and year-round benefits to Piedmont's customers and to the public as a whole. The Commission finds that the Company's commitment to file programs for approval within 45 days of this Order and the strong public policy in support of promoting conservation warrants allowing the proposed $1,275,000 of expenditures for conservation programs to be included in the cost of service in this proceeding. Therefore, the Commission finds and concludes that these provisions are just and reasonable under the circumstances of this particular case and should be approved subject to the additional filing and reporting requirements discussed below. Consequently, consistent with the Stipulation, within 45 days following the issuance date of this Order, the Commission requires Piedmont to file its specific program proposals for review and approval by the Commission. Such filing of Piedmont's conservation programs should be made in accordance with Commission Rule R6-95,[1] where applicable, for any proposed programs. Additionally, the Commission believes that it is reasonable to require that the Company's soon-to-be-filed package of conservation proposals include one or more programs which offer an opportunity for all residential and commercial ratepayers to participate, if they so choose. Subsequent to Piedmont's formal filing of its conservation program proposals, the Commission will provide an opportunity for interested parties to comment on such proposals. Thereafter, the Commission will review all filings concerning this matter and subsequently issue an order regarding the same.

Further, in Piedmont's September 25, 2008 supplemental filing, Piedmont states that, "Upon Commission approval of its Conservation Programs, Piedmont will finalize and execute written agreements with the energy services contractors. Piedmont anticipates that this contractual process will take no more than two months." Thus, the Commission understands that it will take a month or two after Commission approval for Piedmont to have its programs up and running. Consequently, the Commission finds and concludes that it is appropriate and reasonable to require that, to the extent the Company does not actually incur expenditures of $1,275,000 for its conservation programs in the first year, Piedmont should be required to spend the remaining balance in the following year, in addition to the $1,275,000 for that next year.

In addition, the Commission also requires that the Company file annual reports of expenditures detailing the funds spent on its conservation programs by June 15th for each calendar year. The first of these reports should be filed by June 15, 2009. Furthermore, the

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[1] Rule R6-95 (Incentive programs for natural gas utilities) was adopted by Commission Order Adopting Final Rules, issued February 29, 2008, in Docket No. E-100, Sub 113. As used in Rule R6-95, "Program" means any natural gas utility action or planned action that involves offering "Consideration," as defined in said rule.

Commission is of the opinion that these annual reports should provide detailed information for each program that will be beneficial in analyzing the effectiveness of having such programs in place, i.e., are such programs worthwhile; are the total costs of each program reasonable in light of the benefits from the perspective of societal benefits and benefit-cost ratio analyses, where feasible; and should such programs be continued. Thus, the Commission does not consider that such reports would be filed simply "for informational purposes." Such reports should include relevant and useful information for each individual program such as (1) the purpose of program; (2) the duration of program; (3) the classes of persons to whom program are offered; (4) the number of participants; (5) the annual amounts for each element of cost incurred in connection with such programs, e.g., labor, advertising, contracts, materials, equipment, direct payments, rebates, etc.; (6) the anticipated and achieved energy savings in total and average savings per customer; (7) the total dollar savings and average savings per customer; (8) any sources and amounts of funding from third parties, and the reasons those parties are providing such funding; (9) a description of the tests used in evaluating program cost effectiveness and the results of applying those tests; (10) any proposed program modifications; and (11) any other pertinent information. The Commission encourages the Company, the Public Staff, and the Attorney General to engage in discussions, at their convenience, for the purpose of developing a consistent, relevant, and systematic reporting format to be followed by the Company in its annual reports, which should include the aforementioned information and other additional data and analyses to be used in performing and providing a proper and adequate evaluation of the effectiveness of Piedmont's conservation programs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence for this finding is contained in Item 11 of NCUC Form G-1 that was filed with Piedmont's Petition. As shown therein, the Company expended $250,000 to fund the North Carolina portion of GTI expense, and these expenses have been included in the $266,078,482 of operating expenses set forth in Paragraph 6 and Exhibit A to the Stipulation. Pursuant to the Commission's Order in Piedmont's last rate case (Docket No. G-9, Sub 499), the Company was allowed to fund GTI research and development activities through annual payments of $250,000. No party has contested the continued funding of GTI at this annual level. The Commission has carefully considered the GTI funding issue, and concludes that continued funding of GTI at $250,000 is just and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence for this finding is contained in the prefiled testimony of Company witnesses Skains, Feingold, and Carpenter; in the supplemental testimony of Company witness Carpenter; in the hearing testimony of Company witnesses Dzuricky, Yoho, and Carpenter; and in the Stipulation.

With regard to the MDT, the Stipulation provides as follows:

> 9. Adoption of Margin Decoupling Mechanism. As authorized by G.S. 62-133.7, the Stipulating Parties agree that it is appropriate to continue the Company's proposed Margin Decoupling Mechanism (currently known as the Customer Utilization Tracker or CUT) in the form of Appendix C to the

Company's Service Regulations, attached hereto as Exhibit F and designated as the "Margin Decoupling Mechanism." The "R" values and heat factors to be used in the Company's Margin Decoupling Mechanism in the future are set forth in Exhibit D attached hereto and incorporated by reference herein. [1]

Company witness Skains explained that seeking a continuation of the decoupling mechanism originally approved in Piedmont's last general rate case, which otherwise expires on November 1, 2008, was one of the factors that prompted Piedmont to file this case. Witness Carpenter testified that a continuation of the mechanism is appropriate in this case in order to better ensure fixed cost recovery by the Company under a predominantly volumetric rate structure, compensate for declining usage per customer over which the Company has no control, align the Company's interests with those of its customers with respect to conservation of natural gas, and reduce risk to both customers and the Company arising from variations in average per-customer usage arising from all causes.

Company witness Feingold testified that a number of factors currently influencing the natural gas distribution business – including weather, customer use, bad debt expense, energy efficiency and conservation, labor and materials costs, and infrastructure initiatives – have introduced a significant degree of variability into Piedmont's business. He testified that these factors render the traditional volumetric rate structure utilized by many natural gas local distribution companies inappropriate because it no longer provides them with a reasonable opportunity to recover their fixed costs and approved return. As a result, a number of regulatory bodies have been moving toward revenue decoupling, higher fixed charges, tracking rate mechanisms, and return stabilization mechanisms. According to witness Feingold, both the National Action Plan for Energy Efficiency and the Energy Independence and Security Act of 2007 support state commission consideration of whether a decoupling mechanism is appropriate. Witness Feingold also identified the factors upon which Piedmont relied in seeking the CUT in Docket No. G-9, Sub 499, which were (1) aligning customer and Company interests; (2) decoupling margin recovery from customer usage patterns; (3) facilitation of Company efforts to promote conservation; (4) more efficient recovery of fixed costs; (5) facilitation of the Company's ability to achieve its approved margin; (6) sending appropriate price signals; and (7) elimination of the need for an independent weather normalization adjustment mechanism. He testified that these factors continue to support the adoption of a decoupling mechanism for Piedmont. He also testified that the use of the MDT will eliminate the need for a weather normalization adjustment.

The proposed MDT addresses the issue of declining per-customer usage of natural gas. Witness Carpenter pointed out that the average annual weather-normalized residential usage per customer has declined from 72 dekatherms to 63 dekatherms since Piedmont's last general rate case and that average annual residential usage had actually fallen from 72 dekatherms to 62 dekatherms before recovering to 63 dekatherms in the most recent year. He added that appliance efficiency gains; tighter home envelopes; more volatile wholesale natural gas prices; and conservation practices and programs have contributed to the decline. Piedmont witness

[1] The Commission notes that in Appendix C to the Company's North Carolina Service Regulations, as attached to the Stipulation as Exhibit F, reference is made to the "Margin Decoupling Tracker," rather than "Margin Decoupling Mechanism." The Commission will use "Margin Decoupling Tracker" and "MDT" in this Order.

Feingold stated that the traditional volumetric structure of rates does not allow for the full recovery of a utility's nongas cost of service when the test-year volumes used to establish rates are not reached.

The Company witnesses testified that, while the Company has added new customers, the growth in plant necessary to serve them has exceeded the revenues derived from those customers. Therefore, any decline in per-customer usage will not be offset by growth in the number of customers served. Company witnesses testified that, if per-customer natural gas consumption increases, the MDT adjustment will prevent the Company from recovering more than the margin set in this rate case. If per-customer usage continues to decline, even with the MDT mechanism, customers using less gas will have lower bills because the largest component of their bills is the cost of gas.

The Attorney General conducted cross examination regarding Piedmont's existing CUT and whether some form of cap on the MDT would be appropriate. Company witnesses Dzuricky and Carpenter opposed any such cap.

Based on the evidence as a whole, the Commission will adopt the proposed MDT mechanism. Recently enacted legislation authorizes the Commission to approve a mechanism that tracks and trues-up gas utility rates for variations in average per-customer usage upon making certain findings. G.S. 62-133.7 states, "The Commission may adopt a rate adjustment mechanism only upon a finding by the Commission that the mechanism is appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in the general rate case proceeding and that the mechanism is in the public interest." The Attorney General opposed Piedmont's proposal to create such a rate mechanism. The Attorney General argued that the proposed MDT (1) is not in the public interest when viewed in the context of the policies in Chapter 62 and (2) is not appropriate, i.e., that it will not function to produce the intended result.

With regard to the public interest, the Attorney General contended that the proposed MDT is overly broad as a tool for stabilizing revenues and that the benefits to the utility in terms of revenue stability and energy conservation incentives are not sufficient to offset the harm to consumers from frequent, unsupervised rate adjustments and upward pressure on rates. From the consumers' perspective, the MDT increases the variability of rates because it allows rate changes twice per year and does not limit the amount by which rates may increase. The Attorney General argued that the proposed MDT guarantees the utility full recovery of margin from residential and commercial customers without regard to volumes sold, thereby reducing shareholder risk and transferring considerable risk to customers. The Attorney General contended that, in order to be fair, consumers should realize a corresponding benefit, but no such benefit has been proposed. The Attorney General stated that, while the utility contended that the purpose of the MDT is to moderate revenues, the MDT will in fact grow revenues over time. With its customer base increasing, to the extent that the Company is shielded from the effect of declining per-customer consumption, its prospects for revenue growth are greatly enhanced. Further, the Attorney General argued that the proposed MDT is not tailored to encourage effective utility-sponsored energy conservation programs and that other incentives would likely be more effective and less costly.

In addition to a finding of the public interest, the Commission must also find that the proposed MDT is "appropriate" in order to approve it. The Attorney General argued that the Company has not shown that the MDT is designed appropriately because there is a "considerable delay" between deferral and recovery: most revenue deferrals are recorded during winter months, but the MDT would tend to increase rates at other times of the year, when natural gas is used for different purposes. The Attorney General contended that the proposed MDT does not provide sufficient safeguards when the semiannual rate adjustments are made: other factors that might affect the need for a rate adjustment are not examined and the scrutiny of proposed MDT adjustments is "cursory." Finally, if approved, the Attorney General argued that it would be advisable to limit the MDT mechanism to a period of years unless it is reauthorized in a future general rate case.

The Commission has considered the Attorney General's arguments against the proposed MDT and finds them unpersuasive. First, the level of usage per customer established in a rate case is an assumption used to allocate revenue responsibility for the approved revenue requirement across a volumetric rate structure. This assumption inevitably turns out to be inaccurate in practice due to a variety of factors. Without the MDT, this inaccuracy benefits either the Company, if actual usage is greater than assumed usage, or the customer, if actual usage is lower than assumed usage. Under the MDT, both the Company and its customers know exactly how much margin the Company will collect from residential and commercial customers, which is the amount the Commission has determined to be reasonable.

Second, the proposed MDT tracks margin revenues against the Commission-approved margin levels and trues-up variations in margin recovery over time. The mechanism is bilateral in nature: it protects customers from an overcollection of margin revenues to the same degree that it protects the Company from an undercollection of margin revenues. In this manner, it protects against the possibility that the Company may receive a windfall between rate cases due to changes in residential and commercial customer usage. It is also clear from the evidence that the proposed MDT, in and of itself, will not cause the Company to overearn. The MDT will recover only Piedmont's approved margin from residential and commercial customers.

Third, while the MDT works to avoid both overcollection and undercollection of margin revenues based on changes in residential and commercial customer usage, it is clear that there is a general trend toward reduced usage. Piedmont witness Carpenter testified that the decline in use per customer between rate cases has been significant. Piedmont witness Yoho testified that the MDT aligns the Company's interests and the ratepayers' interests with regard to efficiency and conservation.

Growth on the Company's system is responsible for increases in margin revenues between rate cases, but this also occurred under traditional rate designs before the MDT. Furthermore, Company witness Dzuricky testified that Piedmont has seen a decline in the rate of annual growth in the last year or two compared to the growth rates experienced during the last 10 to 15 years. Even with continued growth, it is equally clear, however, that increased margin revenues do not automatically mean an increased return for the Company. When a utility adds customers, it also incurs additional costs to install and maintain facilities and otherwise support service to the additional customers. The additional margin revenues received for serving the new customers are an offset against the additional costs, but do not typically cause a utility to overearn its rate of return. In fact, Piedmont witness Carpenter testified at the hearing that the addition of customers between rate cases typically erodes margin because the costs of serving new customers tend to be higher than the costs of serving existing customers. The fact that the Company's margin revenues increased while the CUT was in effect does not indicate any flaw in the decoupling mechanism, but instead simply indicates that Piedmont is continuing to experience system growth as it has for many years and that growth produces additional margin revenues. One of the advantages of the MDT is that any growth that adds margin revenues at a rate higher than that approved by the Commission in this case will actually lower rates for existing customers.

The Attorney General argued that customers receive no benefit from the MDT. However, in this rate case, Piedmont witness Carpenter stated that the Company would not have accepted the settlement package, which includes the 10.60% return on equity, without the MDT, although he stated that there was no "quantification on any impact" relating to the MDT. The Commission has testimony before it that the Company agreed to give up a higher return on equity and higher monthly charges in exchange for the MDT. The Commission accepts this testimony, so that the Commission cannot agree with the Attorney General's assertion that customers will receive no benefit.

The Commission disagrees with the contention that the MDT will remove the Company's incentive to operate efficiently. Piedmont witness Carpenter testified that the MDT does not fully protect the Company against an erosion of its earned return, since it does not address recovery of revenues from rate classes other than the rate classes covered by the MDT and does not address the level of expenses. The Commission also finds that the MDT is fair to customers. If per-customer natural gas consumption increases, the MDT adjustment will prevent the Company from recovering more than the margin set in this rate case. If per-customer usage declines, even with the MDT, customers using less gas will have lower bills because the largest component of the customers' bills is the cost of gas and that is not subject to the MDT mechanism.

The MDT mechanism requires monthly reports to be filed showing activity in the MDT deferred accounts, requires 14 days notice to implement a rate adjustment under the MDT, and clearly provides that adjustments will be filed "for Commission approval." The Attorney General argues that such procedures are inadequate, that scrutiny will be "cursory," and that other factors will not be examined. The Commission orders that notice of the MDT mechanism explaining its purpose and workings shall be given to all affected customers following the issuance of this Order and to new customers and, thereafter, that notice of each increment or decrement approved as a result of the Company's semiannual MDT rate adjustment filings shall be given with the first monthly bill reflecting the rate change. The Commission finds such notice to be adequate. The original public notice of this rate case proceeding ordered back in April 2008 gave notice that the MDT was proposed. The public has had notice and ample opportunity to weigh in on the policy considerations for and against the MDT. Once approved, the MDT adjustments will essentially be calculated and reviewed according to the mathematical formula set forth in the tariff. It is true, as argued by the Attorney General, that many factors will not be considered when the MDT adjustments are made, but that is inherent in the nature of the MDT mechanism. The MDT is not intended to operate as a mini-rate case in which all factors that might affect rates will be considered.

The Commission will not place any caps on the MDT. While it may be possible to design a capped MDT mechanism, there is no evidence in the record to support caps or explain how they would be designed or implemented or what effect they would have on ratepayers or the Company. Although the Attorney General referred to mechanisms in other states with such caps, he did not propose such a mechanism in this case. Further, adoption of a capped mechanism would maintain the adverse interests of the Company and its customers with respect to conservation. A major advantage of the MDT is that it neutralizes the Company's interest in maximizing customer usage. If a capped MDT mechanism were implemented, the Company would continue to have an interest in promoting customer usage because profits would increase if customers used more gas. Company-sponsored conservation programs would be at odds with the interests of the Company's shareholders since the successful conservation programs would decrease usage and Company profits. For the reasons cited above, the Commission finds that a capped MDT mechanism should not be adopted.

Similarly, the Commission will not adopt the Attorney General's suggestion that the MDT, if authorized at all, be limited to a three-year life and terminated unless reauthorized in a future proceeding. The Commission has had some experience with a MDT mechanism, by way of the three-year CUT experiment authorized for Piedmont in Docket No. G-9, Sub 499. While it is true that this experiment covered a truly extraordinary time and while it will be interesting to see how the MDT works in the future under what will presumably be very different conditions, the Commission, rather than prescribing a three-year life for the MDT, will instead simply note its authority to review and reconsider its orders. As with all orders, the Commission retains authority under the provisions of G.S. 62-80 to revisit the MDT mechanism, on its own motion or on motion of a party, should circumstances justify such.

The Commission has carefully reviewed the evidence in this proceeding with regard to the question of whether the proposed MDT should be approved as agreed by the Stipulating Parties. The Commission has carefully considered all of the Attorney General's arguments in light of the legal standard set forth by the General Assembly in G.S. 62-133.7. Based on this analysis, the Commission concludes that the MDT as stipulated is appropriate because it effectively operates as intended to decouple the Company's margin recovery from the usage patterns of its customers and that the mechanism is otherwise in the public interest because it stabilizes margin recovery for the Company and its customers, reduces risk to the Company and its customers arising from potential variations in usage patterns from multiple causes, facilitates the continued utilization of a volumetric rate structure, helps to preserve the Company's ability to recover its approved margin, ensures that the Company will not over-recover its approved margin, removes Company disincentives pertaining to efficiency efforts and conservation programs, and reduces the need for the Company to make future rate filings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25 AND 26

Various Company witnesses, including witnesses Carpenter and Williams, testified to the proposed additional changes in the Company's tariffs and service regulations, other than those addressed hereinbefore, and the reasons underlying those changes. In general, they testified that these changes were necessary and appropriate to reflect the changes in market, usage, and regulatory conditions and to improve service. The Stipulating Parties agreed in the Stipulation that some, but not all, of the proposed changes to the Company's tariffs and service regulations were appropriate. The proposed changes to the Company's tariffs and service regulations, which were agreed to among the Stipulating Parties, are reflected in Exhibits E and Exhibit F to the Stipulation. No party objected to these changes.

The Commission has carefully reviewed these changes to the Company's service regulations and tariffs and concludes that they are just and reasonable and should be approved, with one minor modification. Specifically, in Piedmont's service regulations, at section "3. Applicable Documents Defining Obligations of the Company and its Customers." the Commission's web site address is referenced as www.ncuc.commerce.state.nc.us/; this should be changed to www.ncuc.net. While the longer address may still be used to gain access to our web site, the shorter address is easier to remember and preferable to the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The Company states in Item 19 of its NCUC Form G-1 filing requirements that the AFUDC rate is computed for North Carolina using the Company's overall rate of return allowed by the Commission in its most recent general rate case. This method for determining AFUDC has been used consistently by the Company for, at a minimum, 20 years. In response to an inquiry from the Commission, Company witnesses Carpenter and Dzuricky mistakenly indicated that the Company would employ the AFUDC method set forth in the Federal Energy Regulatory Commission uniform system of accounts. In its Late-Filed Exhibit filing, Piedmont identified this mistake and indicated that it was not the intent of the Stipulating Parties to change the method by which AFUDC was calculated. Piedmont further requested that the Commission approve Piedmont's continued use of the approved overall rate of return as the appropriate method for determining the AFUDC rate for Piedmont.

The Commission believes that the AFUDC method that has been historically used by the Company is reasonable in that it has been formally approved by the Commission for use by Public Service Company of North Carolina, Inc. (Docket No. G-5, Sub 481); is reflective of the Company's financing costs; has been subject to review in at least eight Piedmont general rate case proceedings; and is supported by the Stipulating Parties. Based upon the foregoing, the Commission concludes that it is appropriate for Piedmont to use the approved overall rate of return in this general rate case proceeding as its AFUDC rate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence for this finding is contained in the Company's Application, the Stipulation; and the supplemental testimony of Company witness Carpenter. The Company's Application seeks an annual increase in its rates and charges of more than $40.5 million. According to Company witness Carpenter, the Public Staff engaged in an extensive review and investigation of Piedmont's filing, including the submission of hundreds of data requests and almost two weeks of on-site audit activities. These activities were followed by extensive negotiations between the Company, the Public Staff, and each of the other Stipulating Parties. These actions ultimately resulted in the Stipulation, which provides for a rate increase of $15.7 million or roughly 39% of Piedmont's original rate increase request. This represents approximately a 1.5% increase in the Company's total operating revenues. It further results in a reduction in both Piedmont's overall rate of return and allowed rate of return on common equity from those approved in Piedmont's last general rate proceeding. These facts demonstrate that the Stipulation results in a substantially smaller rate increase for Piedmont's customers than was requested by the Company. The Stipulation is supported by all active parties in the case except for the Attorney General, who actively opposes only the continuation of the margin decoupling mechanism.

For the reasons set forth above and in the foregoing paragraphs, the Commission concludes that the Stipulation provides a just and reasonable resolution of all the issues in this case; will allow the Company a reasonable opportunity to earn a fair return; and provides just and reasonable rates to all customer classes. Therefore, the Commission finds and concludes that all of the provisions of the Stipulation, taken together, are just and reasonable under the circumstances of this proceeding and should be approved, subject to the additional filing and reporting requirements related to the conservation program process.

The following Schedule 1 summarizes the net operating income for return, rate base, and overall rate of return under present rates and approved rates as agreed to by the Stipulating Parties, and as approved herein by the Commission. As reflected in Schedule 1, Piedmont is granted an increase in its annual level of operating revenues of $15,680,742, based upon the adjusted test-year level of operations approved herein.

SCHEDULE 1

PIEDMONT NATURAL GAS COMPANY INC.
Docket No. G-9, Sub 550
STATEMENT OF NET OPERATING INCOME FOR RETURN, RATE BASE, AND OVERALL RATE OF RETURN
For the Test Period Ended December 31, 2007

Item	Per Company (a)	Adjustments (b)	After Adjustments (c)	Rate Increase (d)	After Rate Increase (e)
NET OPERATING INCOME FOR RETURN					
Operating Revenues:					
Sales and transportation of gas	$ 989,730,781	$ 25,228,182	$1,014,958,963	$15,680,742	$1,030,639,705
Special contract revenues	28,169,546	2,520,002	30,689,548		30,689,548
Other operating revenues	4,596,015		4,596,015		4,596,015
Total operating revenues	1,022,496,342	27,748,184	1,050,244,526	15,680,742	1,065,925,268
Cost of gas	662,367,534	22,659,138	685,026,672		685,026,672

Margin	360,128,808	5,089,046	365,217,854	$15,680,742	380,898,596
Operating Expenses, Excl COG:					
Operating and maintenance	159,923,484	(11,644,945)	148,278,539	66,578	148,345,117
Depreciation	61,495,770	1,306,961	62,802,731		62,802,731
General taxes	17,588,873	(87,108)	17,501,765		17,501,765
State income tax (6.9%)	5,537,856	1,081,184	6,619,040	1,077,377	7,696,417
Federal income tax (35%)	26,081,136	5,105,864	31,187,000	5,087,875	36,274,875
Amortization of investment tax credits	(310,593)		(310,593)		(310,593)
Rounding Adjustment				1	1
Total operating expenses, excl COG	270,316,526	(4,238,044)	266,078,482	6,231,831	272,310,313
Interest on customer deposits	(1,129,186)		(1,129,186)		(1,129,186)
Amortization of debt redemption premium	(77,801)		(77,801)		(77,801)
Net Operating Income for Return	$ 88,605,295	$ 9,327,090	$ 97,932,385	$9,448,911	$ 107,381,296
RATE BASE					
Plant in service	$2,022,736,776	$35,656,721	$2,058,393,497		$2,058,393,497
Accumulated depreciation	(742,023,027)	1,677,510	(740,345,517)		(740,345,517)
Customer advances for construction	(289,734)		(289,734)		(289,734)
Net plant in service	1,280,424,015	37,334,231	1,317,758,246		1,317,758,246
Allowance for working capital	146,520,872	(13,278,404)	133,242,468		133,242,468
Deferred income taxes	(194,101,212)	(1,321,597)	(195,422,809)		(195,422,809)
Unamortized debt redemption premium	94,008		94,008		94,008
Rounding Adjustment		(1)	(1)		(1)
Original Cost Rate Base	$1,232,937,683	$22,734,229	$1,255,671,912		$1,255,671,912
Overall Rate of Return on Rate Base	7.19%		7.80%		8.55%

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont is hereby authorized to adjust its rates and charges in accordance with the Stipulation in this proceeding (as such rates may be adjusted for any changes in the Benchmark Cost of Gas, and changes in Demand and Storage Charges prior to the effective date of the revised rates) effective for service rendered on and after November 1, 2008.

2. That Piedmont is hereby authorized to implement the tariffs attached to the Stipulation as Exhibit E effective November 1, 2008.

3. That Piedmont is hereby authorized to implement the Service Regulations filed as Exhibit F to the Stipulation effective November 1, 2008.

4. That Piedmont shall file tariffs and service regulations to comply with this Order within five days from the date of this Order.

5. That, in the true-up of fixed gas costs for periods subsequent to October 31, 2008, in proceedings under Rule R1-17(k), the Company shall use the fixed gas cost allocations set forth in Exhibit C to the Stipulation.

6. That the decoupling mechanism factors set forth on Exhibit D to the Stipulation are approved for use in the implementation of the provisions of that mechanism subsequent to October 31, 2008.

7. That Piedmont shall file its specific conservation program proposals and the amounts allocated to each such program for approval by the Commission, pursuant to Rule R6-95, within 45 days from the issuance date of this Order. Piedmont shall file annual reports accounting for its conservation program spending for the previous year on or before June 15th of each year. In addition, such annual reports shall include specific detailed information for each program that provides an analysis of the effectiveness of each program as discussed hereinabove. The first of these reports shall be filed by June 15, 2009.

8. That, if Piedmont does not incur $1,275,000 of expenditures for its conservation initiatives in the first year that the new rates are in effect, the Company shall spend that balance in the following year in addition to the $1,275,000 for that year.

9. That Piedmont is hereby authorized to implement the other actions, practices, principles, and methods agreed upon in the Stipulation and not inconsistent with this Order.

10. That Piedmont shall send the notice attached hereto as Appendix A to its customers beginning with the next billing cycle that includes the rate changes approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of October, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh102408.02

APPENDIX A
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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 550

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas Company, Inc., for a General Increase in its Rates and Charges	)	PUBLIC NOTICE

The North Carolina Utilities Commission issued an Order allowing Piedmont Natural Gas Company, Inc. (Piedmont or the Company), to increase its rates and charges by approximately $15.7 million annually, or 1.5% overall, effective November 1, 2008.

On March 31, 2008, Piedmont filed an application seeking a general increase in its rates and charges, approval of changes to its rate design, rate schedules and service regulations, permanent extension of its margin decoupling mechanism, approval of certain energy conservation and efficiency programs and recovery of associated costs, and approval of GTI research and development funding.

In its application, the Company requested an increase of approximately $40.5 million annually. The Company stated that the increase was needed because it has been adding customers and making capital improvements in its utility properties. Since its 2005 rate case, Piedmont has added over 53,000 new customers. The reasons cited by the Company in support of its request for a rate increase were to allow it to maintain its facilities and services in accordance with the reasonable requirements of its customers, to compete in the market for capital funds on fair and reasonable terms, and to produce a fair profit for its stockholders.

The increase approved by the Commission was the result of a stipulation (Stipulation) entered into between the Company and other parties to the proceeding, including the Public Staff – North Carolina Utilities Commission. The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service. These approved increases are associated with allowed expenses and return on investment only and do not contemplate increases or decreases that may occur in association with gas cost adjustments to rates as allowed by G.S. 62-133.4.

APPENDIX A
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Overall, the Commission has approved a residential rate increase for the Company of 1.65%, although individual residential customers may experience larger or smaller percentage increases due to a change in the Company's rate design and the elimination of the value/standard residential rate categories.

The Commission has approved the continuation of Piedmont's margin decoupling mechanism, which will allow the Company to recover its approved margin independent of customer usage patterns and will protect customers from the potential over-recovery of margin by the Company. The margin decoupling mechanism will track margin recovery on a monthly basis and result in semi-annual adjustments to usage rates to refund or recover differences.

The Commission has also approved the annual expenditure of $1.275 million on conservation and energy efficiency programs and directed the Company to file its initial program proposals for approval by the Commission within 45 days from the date of the Commission's Order.

A list of approved rates effective November 1, 2008, can be obtained from the Company's website, www.piedmontng.com, or at the Office of the Chief Clerk of the Commission, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, where copies of the Commission's Order and the Stipulation are available for review by any interested party. The Commission's Order and the Stipulation, as well as other filings in these dockets can be viewed/printed from the Commission's website at www.ncuc.net using the Docket Search function.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of October, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

(SEAL)

DOCKET NO. P-21, SUB 71
DOCKET NO. P-35, SUB 107
DOCKET NO. P-61, SUB 95

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petitions of Ellerbe Telephone Company, MebTel, Inc., and Randolph Telephone Company for Arbitration with ALLTEL Communications and Cingular	)	ORDER RULING ON OBJECTIONS AND REQUIRING THE FILING OF COMPOSITE AGREEMENTS

BEFORE: Commissioner William T. Culpepper, III, Presiding, and Chairman Edward S. Finley, Jr., Commissioner Robert V. Owens, Jr., Commissioner Sam J. Ervin, IV, Commissioner Lorinzo L. Joyner, and Commissioner Howard N. Lee

BY THE COMMISSION: On December 20, 2007, the Commission issued its *Recommended Arbitration Order (RAO)* in these dockets[1]. The Commission Panel made the following:

FINDINGS OF FACT

1. A CMRS Provider must choose a single Point of Interconnection (POI) on the RLEC's networks that is within the CMRS Provider's Major Trading Area (MTA) for the interconnection of the parties' networks. Each party is technically and financially responsible for transporting and delivering its originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of completing the call beyond the POI.

2. The RLECs are technically and financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for transit charges, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI.

3. The appropriate reciprocal compensation rate is determined by applying the evidence and conclusions as set forth herein as applicable for Ellerbe, MebTel, and Randolph. The RLECs should modify their respective alternative cost studies to reflect the Commission's conclusions.

4. Because the Commission modified the reciprocal compensation requirements of Section 251(b)(5) of the Act (the Telecommunications Act of 1996 or TA96), pursuant to Section 251(f)(2) of the Act, in Docket No. P-100, Sub 159, the RLECs are not required to perform total element long run incremental cost (TELRIC) studies to establish reciprocal compensation rates, and the rates proposed for reciprocal compensation do not have to comply

[1] The *RAO* was issued by Commissioner Culpepper, presiding, Chairman Finley, and Commissioner Owens with Chairman Finley dissenting from the Majority on Findings of Fact Nos. 1 and 2.

with all of the requirements set forth in Section 252(d) of the Act and the related FCC (Federal Communications Commission) rules.

5. Cingular is to develop a 30-day originating traffic study, which is to be used in establishing a default interMTA traffic factor. The parties are encouraged to negotiate between themselves. The Public Staff is encouraged to offer its good offices to the parties to resolve this issue.

6. When an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber and that subscriber is roaming outside the MTA at the time the call is made it is an interMTA call, and the RLEC is entitled to be paid originating access by the CMRS Provider.

7. The investment in the Mebane DMS switch should be excluded from MebTel's cost study.

8. It is not appropriate to alter MebTel's proposed switch investment per line as proposed by the CMRS Providers. However, in Finding of Fact No. 7, the Commission has concluded that the parties have agreed that the investment in the Mebane DMS switch should be excluded from MebTel's cost study. Therefore, the Commission agrees that MebTel's proposed total switch investment per line of $458 should be used; however, this figure should be adjusted based on the Commission's conclusions concerning usage sensitive switching costs discussed in Finding of Fact No. 10.

9. An annual cost factor of 30.5% should be used for MebTel to compute switching annual costs per line.

10. MebTel's transport and termination rate should not recover its nonusage sensitive switching costs. Further, 38% of total switching annual costs per line should be recovered by MebTel's transport and termination rate.

11. Randolph's alternative cost study is based upon appropriate cost data and should be adopted. However, Randolph should update its alternative cost study to reflect the National Exchange Carriers Association (NECA) average schedule formulas adopted for the one-year period beginning on July 1, 2007 and the most current Local Switching Support (LSS) formulae.

12. Although Randolph's alternative cost study uses embedded costs to some degree with forward-looking demand units, Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order*[1].

13. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use

[1] *Order Granting Modification Under Section 251(f)(2)*, issued in Docket No. P-100, Sub 159 on March 8, 2006 (hereinafter referred to as the *Modification Order*).

embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23A is moot.

14. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23B is moot.

15. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23C is moot.

16. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23D is moot.

17. It is appropriate to request Randolph and the CMRS Providers jointly to review Randolph's continuing property records to attempt to agree on the appropriate Randolph-specific usage sensitive switching costs to be included in Randolph's alternative cost study.

18. Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate.

19. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25A is moot.

20. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25B is moot.

21. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25C is moot.

22. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25D is moot.

23. It was appropriate for Ellerbe to adopt Randolph's cost study as modified herein.

24. The alternative cost study Guidelines adopted by the Commission in Docket No. P-100, Sub 159 do not require the RLECs to use forward-looking costs in all facets of their alternative cost studies.

25. Only the traffic-sensitive costs of a switch comprise the direct costs associated with terminating local traffic and should be recouped through reciprocal compensation rate. The non-traffic sensitive component of end office switches is necessary regardless of whether local traffic is routed through the switch.

26. Only the direct costs for central office investments associated with the additional cost of terminating local traffic should be included in the RLECs' alternative cost studies - that is, the part of the switch that is considered to be traffic-sensitive and not associated with the line port.

27 - 29. In the Evidence and Conclusions for Findings of Fact Nos. 7 through 10, the Commission addressed the CMRS Providers' objections to the alternative cost study filed by MebTel. In its conclusions for these findings, the Commission indicated what adjustments or changes to the study are required to meet all the Guidelines established in Docket No. P-100, Sub 159. Once these adjustments are made, MebTel's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159. Likewise, for Randolph's study, the Commission has addressed objections raised by the CMRS Providers in the Evidence and Conclusions for Findings of Fact Nos. 11 through 22. The Commission has spelled out the necessary adjustments necessary to meet the Guidelines it established in Docket No. P-100, Sub 159. Once these adjustments are made, Randolph's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159. By the same token, Ellerbe should make similar adjustments.

On February 22, 2008, after being granted extensions of time to file objections, Alltel Communications, Inc. (Alltel) and New Cingular Wireless PCS, LLC formerly d/b/a Cingular Wireless, now d/b/a AT&T Mobility (AT&T Mobility) (jointly the commercial mobile radio service (CMRS) Providers), MebTel, Inc. (MebTel), and Randolph Telephone Company (Randolph) each filed Objections to the *RAO*. Also on February 22, 2008, comments on the *RAO* were filed by the following interested companies not parties to the proceeding: Carolina Telephone and Telegraph Company LLC and Central Telephone Company (Embarq), Time Warner Telecom of North Carolina, L.P. (TWTC) and the Competitive Carriers of the South, Inc. (CompSouth[1]), and Cellco Partnership d/b/a Verizon Wireless, on behalf of itself and its wireless affiliates (Verizon Wireless).

The following table summarizes the Objections received to the *RAO*:

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[1] CompSouth members include the following providers of competitive local exchange services in North Carolina: ACCESS Integrated Networks, Inc.; Access Point Inc.; Cavalier Telephone; Cbeyond Communications; Covad Communications Company; Deltacom, Inc.; Level 3 Communications; Momentum Telecom, Inc.; NuVox Communications, Inc.; Sprint Nextel; Time Warner Telecom of North Carolina, L.P.; and XO Communications.

Finding of Fact No.	CMRS Providers	MebTel	Randolph
1	Object		
2	Object		
3			
4	Object		
5			
6			
7			
8	Object		
9			
10		Object	
11	Object		Object
12	Object		
13			
14			
15			
16			
17			Object[1]
18			
19			
20			
21			
22			
23	Object		
24			
25			
26			
27	Object		
28	Object		
29			

Embarq filed comments stating that it is concerned about the POI definition outlined in Finding of Fact No. 1 having negative unintended consequences if applied to other carriers not similarly situated to the parties to the arbitration. Embarq requested that the Commission limit the scope of its decision to avoid unintended results. Embarq is also seeking clarification of the transit traffic decision in Finding of Fact No. 2 to allocate responsibility for transport costs explicitly to the interconnecting party. Finally, Embarq also requested that the traffic study

[1] Randolph states that the parties have not been able to agree on the appropriate Randolph-specific usage sensitive switching cost.

imposed by the Commission in Finding of Fact No. 5 capture both originating and terminating traffic[1].

TWTC and CompSouth filed comments addressing Findings of Fact Nos. 1 and 2 of the *RAO*. TWTC and CompSouth requested that the Commission rescind Findings of Fact Nos. 1 and 2 of its *RAO* and issue an Order consistent with Chairman Finley's dissent with regards to those matters.

Verizon Wireless filed comments stating that Findings of Fact Nos. 1 and 2 of the *RAO* contravene the requirements of the Act, as implemented by the FCC, and therefore, must be modified.

On March 4, 2008, the Commission issued an *Order* requesting comments and reply comments on the Objections and comments filed concerning the *RAO*.

On April 23, 2008, Randolph filed a copy of amended Spreadsheet 2 which was originally attached to Randolph's Objections.

After being granted an extension of time to file, initial comments were filed on April 25, 2008 by The Alliance of North Carolina Independent Telephone Companies[2], the CMRS Providers, Embarq, the Public Staff, and the RLECs.

Reply comments were filed on May 14, 2008 by Embarq[3], the CMRS Providers, the RLECs, TWTC and CompSouth, and Verizon Wireless.

Although a Commission Panel issued the original *RAO*, the Objections addressed in this Order have been decided by the Full Commission due, primarily, to the 2-1 vote originally rendered on Findings of Fact Nos. 1 and 2.

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[1] Embarq stated in its reply comments that, while it had previously commented on Finding of Fact No. 5 to advocate inclusion of both originating and terminating traffic in the interMTA traffic study, it understands that the parties have settled this issue and that it is no longer before the Commission. The CMRS Providers stated in their Objections that AT&T Mobility and the RLECs have settled Findings of Fact No. 5 and 6 (Matrix Issue Nos. 8 and 8C; *RAO* Issues 5 and 6), while ALLTEL and the RLECs settled those issues prior to the hearing. The CMRS Providers urged the Commission to note in the Final Order that the issues have been resolved and refrain from endorsing the rulings on those respective issues in the *RAO*. The Commission's rulings on those issues in the *RAO* stand, but, as always, parties are free to negotiate resolutions contrary to the Commission's rulings that are acceptable to each party.

[2] For the purposes of the comments, the Alliance consists of the following: North State Communications, LEXCOM, Citizens Telephone Company, Tri-County Telephone Membership Corporation, Randolph Telephone Membership Corporation, TDS Telecom, Wilkes Telephone Membership Corporation, Skyline Telephone Membership Corporation, Surry Telephone Membership Corporation, Piedmont Telephone Membership Corporation, and Atlantic Telephone Membership Corporation.

[3] On May 19, 2008, Embarq filed a letter notifying the Commission that Exhibit B attached to Embarq's reply comments had minor inaccuracies. Embarq filed a revised version of Exhibit B.

Following is a discussion, by Finding of Fact, of the outstanding Objections to the *RAO*. Appendix A provides a list of the acronyms used in this Order.

FINDING OF FACT NO. 1 (ISSUE NO. 1 – MATRIX ISSUE NO. 1):

CMRS Providers' Statement: How should "Point of Interconnection" (POI) be defined?

RLECs' Statement: Should Point of Interconnection be defined differently for direct traffic and for indirect traffic?

INITIAL COMMISSION DECISION

The Commission concluded that the POI is defined as a single physical, technically feasible point on the RLEC's networks, selected by the CMRS Provider, that is within the CMRS Provider's MTA for the interconnection of the Parties' networks for the exchange of all traffic, direct or indirect.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel did not object to this Finding of Fact.

RANDOLPH: Randolph did not object to this Finding of Fact.

CMRS PROVIDERS: The CMRS Providers objected to Finding of Fact No. 1, asserting that the Commission's findings are contrary to federal law and decisions, most importantly *Atlas Telephone Company v. Oklahoma Corp. Com'n*, 400 F.3d 1256 (10th Circuit, 2005) (*Atlas*). The CMRS Providers further argued that the Commission failed to apply its own established precedent when deciding on the transit charge issue and that the Commission failed to consider conflicting evidence. The Commission also erroneously based its determinations on the claim that RLECs needed protection from competition.

NON-PARTY COMMENTS

EMBARQ: Embarq requested that the Commission limit the scope of its decision to the parties to this proceeding so as to avoid unintended results for ILECs like Embarq with multiple tandems in LATAs or MTAs.

TWTC AND COMPSOUTH: TWTC and CompSouth stated the Commission should reconsider its decision for generally the same reasons as stated by the CMRS Providers.

VERIZON WIRELESS: Verizon Wireless also stated that the Commission should reconsider its decision for generally the same reasons as stated by the CMRS Providers.

Gas or changes in demand and storage charges prior to the effective date of the revised rates), are just and reasonable and should be approved.

19. The Stipulating Parties agreed that the reasonable level for the total cost of gas in this proceeding is $685,026,672, as described in Paragraph 4.B and on Exhibit G to the Stipulation. This provision is just and reasonable and should be approved.

20. The agreed-upon treatment of margin from the City of Monroe, as described in Paragraph 14 of the Stipulation, is just and reasonable and should be approved.

21. The Stipulation provides for the amortization of pipeline integrity management costs and EasternNC deferred operations and maintenance expenses as set forth and described in Paragraph 10 of the Stipulation. This provision is just and reasonable and should be approved.

22. The Stipulation provides that Piedmont will file its proposed conservation programs for approval within 45 days of this Order and that Piedmont will be allowed to recover $1,275,000 of conservation program expenditures through the cost of service in this proceeding, as set forth in Paragraph 13 of the Stipulation. This provision is just and reasonable and should be approved subject to the additional filing and reporting requirements as set forth hereinafter.

23. The Stipulating Parties agreed that the funding of research and development activities through annual payments to the GTI of $250,000 per year, which is included in the overall level of test year operating expenses, as described in Paragraph 6.B of the Stipulation and as set forth on Exhibit A attached thereto, is just and reasonable and should be approved.

24. The Margin Decoupling Tracker (MDT), previously referred to as the Customer Utilization Tracker (CUT), as described in Paragraph 9 and as set forth as Appendix C to Exhibit F of the Stipulation, and the associated margin decoupling mechanism factors, as set forth in Exhibit D to the Stipulation, are appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in this rate case proceeding. The mechanism is in the public interest and should be approved.

25. The agreed-upon tariffs, attached to the Stipulation as Exhibit E, are just and reasonable and should be approved.

26. The agreed-upon Service Regulations, which are reflected in Exhibit F to the Stipulation, are just and reasonable and should be approved, with one minor modification. The Commission's web site address should be referenced as www.ncuc.net.

27. The Stipulating Parties agreed that the overall rate of return approved by the Commission in this proceeding should be used by the Company as its Allowance for Funds Used During Construction (AFUDC) rate. This provision is just and reasonable and should be approved.

interconnection on the RLECs' networks. Under the CMRS Providers' interpretation, they could choose to put their POI anywhere on their own network within their MTA and thus compel the RLEC to pay for transit over great distances. The Commission may appropriately weigh those facts in its decision.

REPLY COMMENTS

RLECs: The RLECs noted that neither the Act nor the FCC regulations establish by their terms where the POI should be located in the event of indirect interconnection. However, to the extent that the POI for interconnection is directly addressed, it is clear that, under Section 251(c)(2)(B) and 47 CFR 51.305, interconnection must occur on the ILEC's network. Thus, the *only* time that the Act speaks to the location of the POI, it clearly provides that it is to be on the ILEC network. While the CMRS Providers argue that, in the case of indirect traffic exchange, the POI must be considered to be at an off-network location that they select, there is no support for that position in the Act or the FCC regulations. To adopt the CMRS Providers' position would be to impose a costly and onerous burden on the RLECs.

CMRS PROVIDERS: The CMRS Providers did not substantially revisit the arguments related to the location of the POI in the event of indirect interconnection. They did, however, express the view that the Commission's consideration of the asserted economic effects on the RLECs of adopting the CMRS Providers' preferred solution to the POI location question was unsupported by substantial evidence and thus "arbitrary and capricious."

ALLIANCE: The Alliance did not file reply comments.

EMBARQ: Embarq reiterated that the apparent POI definition (i.e., one-POI-per-MTA on the ILEC's network) should be clarified to avoid causing unintended transport burdens on larger carriers like Embarq with widely scattered franchise areas. While Embarq agrees that interconnections established by wireless carriers should indeed be located on the ILEC's network, it is unclear that the one-POI-per-MTA rule is what is being promulgated. If it is, then the Commission should clarify the *RAO* by stating that the POI/transport decision applies to per local access and transport area (LATA) or that the ruling here is limited to the parties to the arbitration. Embarq noted that the FCC has not mandated that wireless carriers need to establish only one-POI-per-MTA per incumbent network.

PUBLIC STAFF: The Public Staff did not file reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth argued that the Commission's decision in *ALLTEL* was not dispositive of this issue because the Commission's decision was ultimately rendered moot by the subsequent language agreed to voluntarily by the parties and approved by the Commission. TWTC and CompSouth also noted that the parties had agreed to indirect interconnection despite the fact that the RLECs could have pursued direct interconnection with the CMRS Providers. The insistence on a single POI is inconsistent with this agreement because indirect interconnection, by definition, results in two points of interconnection on either side of the transit provider's network.

VERIZON WIRELESS: The *RAO* requires the CMRS Providers to establish what amounts to a "virtual" network for RLECs to originate land to mobile traffic where the parties have chosen to exchange traffic indirectly. This is unfair and is not supported by law. Verizon Wireless also concurred with the proposition that, because the parties made a voluntary agreement at variance with the *ALLTEL RAO*, the *ALLTEL* decision never became a final decision of the Commission and does not constitute precedent.

DISCUSSION

In Issue No. 1 of the *RAO*, the Commission relied on Section 251(c)(2)(B) of the Act for the proposition that, as a matter of law, the POI as between the RLECs and CMRS Providers had to be on the RLEC's network. The Commission derived this conclusion from the language of Section 251(c)(2) which read, in pertinent part, that among the "Additional Obligations of Incumbent Local Exchange Carriers" were that the RLECs had a "duty to provide, for the facilities and equipment of any requesting carrier, interconnection with the local exchange carrier's network...(B) at any technically feasible point with the carrier's network." After careful consideration of the arguments presented on reconsideration, the Commission concludes that, in this particular case, in which the RLECs have initiated the arbitration, the CMRS Providers cannot be said to the "requesting party" and that Section 251(c)(2)(B) is not, therefore, determinative of the location of the POI. Instead, the POI issue in this proceeding must be resolved on the basis of an analysis of Section 251(a)(1).

Admittedly, the RLECs are in a peculiar situation. The text of Section 252(a) does not allow ILECs to initiate arbitrations. Nevertheless, the FCC in 2005 held that ILECs could initiate arbitrations with CMRS providers. *See, T-Mobile USA Inc. et al., Petition for Declaratory Ruling Regarding Incumbent LEC Wireless Termination Tariffs*, Declaratory Ruling and Report and Order, CC Docket No. 01-92, Released February 24, 2005, at Para. 7. The background to this decision was that the ILECs complained that the CMRS providers were "dumping" traffic on them and that, without a right to arbitration, they had no recourse for obtaining compensation. Since the FCC did not make other corresponding changes to the rights and duties of the parties under the Act, it would appear from the literal language of Section 251 that, when an ILEC initiates arbitration, it cannot effectively cite to Section 251(c)(2) for the principle that the POI should be on its network since Section 251(c)(2) only applies to instances when a CLP is the requesting carrier.

In the instant case, the interconnection architecture is in place, and the parties have agreed upon indirect interconnection. However, the record does not reflect the existence of any agreement between the parties as to where the POI should be located. Practically speaking, the primary significance of the location of the POI in the context of indirect interconnection is that, as a legal matter, the location of the POI determines who bears the responsibility for the payment of transit charges to the third party carrier in the first instance. In other words, if the transiting carrier's facilities are located beyond the POI, then the terminating carrier is responsible for initial payment of the transit charges and is entitled to recoup them from the originating carrier through reciprocal compensation payments. On the other hand, in the event that the transiting carrier's facilities are located on the originating carrier's side of the POI, then the originating carrier is responsible for paying them as part of bearing the cost of delivering the call to the POI.

The central question of Issue No. 1 in these dockets is whether there should be one POI or two (or, theoretically, multiple) POIs.

The Commission continues to believe that, in these dockets, there should be only one POI and it should be located on the RLECs' network. Obviously, in the absence of reliance on Section 251(c)(2), the grounding for that conclusion must be found elsewhere. The Commission believes that such grounding can be found in Section 251(a)(1), which provides that "[e]ach telecommunications carrier has the duty (1) to interconnect directly or indirectly with the facilities and equipment of other telecommunications carriers." This, of course, was the provision that the *Atlas* court relied upon. Unlike the language of Section 251(c)(2), Section 251(a)(1) does not specify the number of POIs or where the POI or POIs should be located. As a result, the literal language of Section 251(a)(1), in an arbitration in which an RLEC seeks interconnection with a CMRS Provider, would seem to provide the Commission with the discretion to determine how many POIs there should be and where they should be located. As a result, the Commission will proceed to determine, on the basis of its sound discretion, the number and location of the POIs for purposes of the parties' interconnection agreements.

In *Atlas,* the Tenth Circuit concluded without further explanation that there were to be two POIs, with each POI to be located where the facilities of the transiting carrier met the facilities of the terminating carrier. Significantly, the two-POI conclusion seems to be assumed rather than proven in *Atlas.* The only place that two POIs are explicitly mentioned in the *Atlas* opinion is in the "Background" section, where it is stated:

> When an RTC customer places a call to a CMRS customer, the call must first pass from the RTC network through a point of interconnection with the SWBT network. SWBT then routes the call to a *second* point of interconnection between its network and the CMRS network. The call is then delivered to the CMRS customer. In contrast, were the RTC and CMRS networks directly connected, the call would pass only through a single point of interconnection. *Atlas* at 1259 (Emphasis added)

From this recitation and its location in the *Atlas* decision, it is unclear from the record whether the parties had agreed to a two-POI solution, the Oklahoma PUC had imposed it without objection from the parties, or the Tenth Circuit had simply assumed it. In any event, the *Atlas* decision provides no sound theoretical justification for the adoption of the two-POI approach and the Commission is unwilling to simply accept the Tenth Circuit's unsupported assertion as binding or persuasive in this proceeding.

The touchstone of the *Atlas* analysis was the Tenth Circuit's view that Section 251(c)(2) applied only to the limited class of ILECs and did not furnish a framework for indirect interconnection. For this reason, *Atlas* relied on Section 251(a)(1)'s requirement that all telecommunications carriers interconnect directly or indirectly. However, as noted by the Commission in the *RAO,* this provision lacks operational content. The *Atlas* court filled that gap by ruling, in effect, that there were two POIs; but this was simply the *Atlas* court's conclusion (or perhaps, more accurately, its characterization), underived from any language in statute or FCC rules to that effect. In fact, the language of Section 251(a)(1) can support a conclusion that, in appropriate circumstances, that there should be only one POI, even in the case of indirect interconnection, if the Commission concludes that such a result is appropriate based on the exercise of its discretion informed by considerations of sound regulatory policy.

The Telecommunications Act places the burden on state commissions to arbitrate such matters, subject to review by federal courts. Leaving aside Section 251(c)(2), the Commission, exercising its sound discretion based upon the record before it, has the authority to conclude under a Section 251(a)(1) that the equities in these cases sustain a one-POI, rather than a two-POI, solution in appropriate instances. By the same token, the equities in other cases may call for a different result.

The equities in these dockets calling for the use of a single POI rather than multiple POIs are, simply stated, the following:

First, there are the relative sizes of the CMRS Providers and the RLECs. The RLECs in these dockets are small, rural telephone companies with limited service areas, while the CMRS Providers are massive entities whose local calling areas, or MTAs, sprawl across states. As such, the CMRS Providers' network can, with only slight exaggeration, be called ubiquitous, while those of the RLECs are small and local. Under that set of circumstances, it is more equitable for there to be a single POI that is located on the RLECs' networks.

Second, the use of a single POI places these RLECs, practically speaking, in the same position as they would have been had they been able to rely on Section 251(c)(2). As noted above, the situation where an ILEC is forced to initiate arbitrations (as per FCC ruling but not the text of the statute) is peculiar and even quirky. The RLECs were given the right to initiate an arbitration proceeding by the FCC in order to prevent them from having traffic "dumped" upon them without compensation. In other words, the ordinary reasons that lead competing carriers to request arbitration do not exist in this instance. The RLECs should not be disadvantaged because the parties from whom they sought compensation did not request arbitration.

Third, the use of a single point in the circumstances of these dockets is conceptually less complicated than the use of multiple POIs. The two-POI solution presupposes the existence of three different networks, while the one-POI solution makes do with two—the transit network in this case being considered a virtual part of the CMRS Providers' network. At the same time, the use of a single point of interconnection and the inclusion of the transit carrier's network as a virtual part of the CMRS Provider's network does not necessarily work to deprive either party of its just compensation for transit.

On the other hand, the Commission is unable to identify any countervailing equities that suggest the appropriateness of a two-POI solution of the type advocated by the CMRS Providers. Although the CMRS Providers have argued that the parties have agreed to multiple POIs, what this argument appears to mean is that the parties have agreed to indirect interconnection and that indirect interconnection inherently involves the use of multiple POIs given the interposition of facilities provided by the carrier performing the transiting function. The Commission does not, however, find this argument persuasive. Although the parties did agree to indirect interconnection, the record does not demonstrate that the RLECs intended for their agreement to this network architecture to involve agreement to multiple POIs. Furthermore, the Commission does not believe that the use of indirect interconnection necessarily assumes the use of multiple POIs. At an absolute minimum, there is nothing in Section 251(a)(1) which mandates such a result. Thus, the Commission concludes, in the exercise of its sound discretion and for the reasons stated above, that there should be a single POI of interconnection located on the RLECs' networks.

It cannot be sufficiently emphasized that the placement of the single POI on the RLEC's network does not relieve the RLEC from paying compensation for that transit on calls originated by RLEC customers. Instead, it simply means that it is not the RLEC's responsibility to reimburse any relevant transit charges in the first instance, assuming that such payment is necessary. Under the arrangement deemed appropriate by the Commission, payment of transit charges will be the CMRS Provider's responsibility in the first instance in connection with RLEC-originated calls. However, the CMRS Providers are entitled to be reimbursed for any transit charges paid in connection with the termination of RLEC-originated calls in the form of reciprocal compensation paid by the RLEC. Any genuine financial disadvantage that may inure to the CMRS Providers from there being a single POI located on the RLEC's network is curable by a proceeding to arrive at an asymmetric reciprocal compensation rate. As noted elsewhere, the reciprocal compensation rate is deemed to include any transit costs, but those costs are not necessarily separately identified. To the extent that this structure creates significant financial undercompensation for the CMRS Provider, this problem can be corrected if there is a proceeding to determine an asymmetrical rate; but, for that to occur, the CMRS Providers will have to request the establishment of an asymmetric reciprocal compensation rate and furnish to the relevant cost data to the Commission.

Accordingly, in the exercise of its sound discretion, the Commission concludes that an alternative basis for a one-POI decision exists based upon Section 251(a)(1). In other words, while the Commission has reached its conclusion for a different reason in this order, the result reached in the RAO with respect to this issue is affirmed and the Objections lodged to that decision by the CMRS Providers are overruled. The Commission will convene a hearing at the request of the CMRS Providers to consider an asymmetrical reciprocal compensation rate relevant to these dockets, provided that the CMRS Providers furnish their relevant cost data.

CONCLUSIONS

The Commission finds it appropriate to deny the CMRS Providers' Objections to Finding of Fact No. 1 and to affirm the original decision.

FINDING OF FACT NO. 2 (ISSUE NO. 2 – MATRIX ISSUE NO. 4)

CMRS Providers' Statement: Is each party obligated to pay for the transit costs associated with the delivery of traffic originated on its network to the terminating party's network?

RLECs' Statement: In the event of indirect interconnection, are RLECs obligated to pay any transit costs assessed by third-party carriers for transport of traffic to a CMRS provider outside the RLEC's service area and network?

INITIAL COMMISSION DECISION

The RLECs are technically and financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for transit charges, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel did not object to this Finding of Fact and the Commission's resolution of this issue.

RANDOLPH: Randolph did not object to this Finding of Fact and the Commission's resolution of this issue.

CMRS PROVIDERS: The CMRS Providers objected to Finding of Fact No. 2, asserting that it is clear that the Act, federal law and FCC regulations require the originating carrier to pay any transit charges imposed by a transiting carrier to deliver traffic to a terminating carrier, plus all costs of facilities linking its own switch to the third party transiting tandem. In their February 22, 2008 filing which was entitled "Objections of Alltel Communications and AT&T Mobility," the CMRS Providers argued that: (1) federal courts in four different circuits, including the Fourth Circuit Court of Appeals, have ruled that the Act does not allow originating incumbent carriers to force CMRS providers to establish direct connections to incumbents' networks, nor to charge CMRS Providers for the costs (such as transit charges) of originating calls and that the *RAO* failed to follow the clear federal law on this issue; and, (2) the *RAO* failed to follow the Commission's previous decision in the *Alltel* case when it held that, when the carriers are indirectly interconnected, the RLECs "are not responsible for transit charges, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI."

NON-PARTY COMMENTS

EMBARQ: Embarq noted that, while the *RAO* specified that the RLECs are not responsible for transit charges beyond the POI based upon the competitive carrier's use of a third party's network facilities, the *RAO* did not specify that the competitive carrier is obligated to pay the transit provider for the use of its network. Embarq requested that the Commission clarify that the competitive carrier is responsible for compensating the transit provider for traffic originated by both the competitive carrier and the incumbent carrier.

TWTC AND COMPSOUTH: TWTC and CompSouth generally agreed with the CMRS Providers' position on this point. Further, TWTC and CompSouth stated that the issue of which party is obligated to pay for transit costs where indirect interconnection is utilized is a critical issue of policy. The *RAO* erroneously determined that the parties must achieve indirect interconnection through a single POI. According to TWTC and CompSouth, the *RAO* requirement that the parties achieve indirect interconnection through a single POI preordains a result which allows the RLECs to avoid any costs associated with transit for calls originated on the RLEC's network.

VERIZON WIRELESS: Verizon Wireless asserted that the *RAO's* on-network POI requirement of Finding of Fact No. 1 predetermined the conclusions of Finding of Fact No. 2. Thus, according to Verizon Wireless, the *RAO's* decision requiring the location of the POI to be on the RLECs' network when the carriers are indirectly connected erroneously mandated that the responsibility for paying the transit costs for calls that originated on the RLEC's network belonged to the CMRS Providers.

INITIAL COMMENTS

RLECs: The RLECs noted that the Commission's Finding of Fact and conclusions of law pertaining to which party pays for the "transit charge" assessed by the third party provider when traffic is exchanged indirectly through a third party tandem are correct and consistent with the prior determinations of the Commission in the *RAO* in the *Verizon Wireless(Alltel)* case. The RLECs were fully supportive of the *RAO* decision that the RLECs do not have financial responsibility for paying transit fees for delivering traffic originated on their network beyond the POI. The RLECs stressed that it was important to distinguish transit cost responsibility from the responsibility to pay reciprocal compensation to a terminating carrier. According to the RLECs, they are responsible for paying reciprocal compensation to cover the terminating carrier's expense for both transport and termination of a RLEC-originated call, and transit charges may be a component of the terminating carrier's transport expense. However, the duty to pay reciprocal compensation does not impose a concomitant duty on the RLECs to pay a transit charge assessed by a third party transit provider.

CMRS PROVIDERS: The CMRS Providers did not file any new comments in opposition to Finding of Fact No. 2 and the resulting conclusion of law.

ALLIANCE: The Alliance noted that the Commission's decisions regarding the location of the POI and the obligation of the CMRS providers to pay the cost of transit when the carriers are indirectly interconnected were correct. With regard to the transit issue, the Alliance argued that the suggestion that the originating ILEC should be responsible for charges assessed by a third party transit carrier would impose a cost on the ILEC which the ILEC is not legally obligated to bear and that no such costs were ever taken into account in establishing ILEC rates.

EMBARQ: Embarq requested that the Commission clarify that the competitive carrier is responsible for compensating the transit provider for traffic originated by both the competitive carrier and the incumbent carrier.

PUBLIC STAFF: The Commission's Findings of Fact Nos. 1 and 2 pertaining to which party pays for the "transit charge" assessed by the third party provider when traffic is exchanged indirectly through a third party tandem are correct. The tandem and transit facilities of the third party provider become a virtual part of the CMRS Providers' network, because the third party providers' facilities are used to connect with the POI on the RLECs' networks. The CMRS Providers pay for the third party transiting facilities in lieu of facilities they would have needed if connecting directly with the RLECs. The cost of the transiting facilities is recovered through the reciprocal compensation rates charged by the CMRS Providers to the RLECs, just as the direct connection facilities would be. Financial responsibility then rests on each party on its own side of the POI. Each party pays reciprocal compensation to the other to cover the cost of completing the call beyond the POI.

REPLY COMMENTS

RLECs: The RLECs did not file any reply comments on this issue.

CMRS PROVIDERS: The CMRS Providers are critical of the RLECs' suggestions that transit costs are recovered as reciprocal compensation and that the CMRS Providers must produce a forward looking cost study to seek reimbursement for the transit rates that they are required to pay to the third party. According to the CMRS Providers, the transit charges are essentially line items that should be passed through. In the opinion of the CMRS Providers, it makes more economic sense for the originating party to pay the transit charge rather than for the terminating carrier to pay the charge and then seek reimbursement from the originating carrier.

The CMRS Providers opposed Embarq's request that the Commission clarify the *RAO* to indicate that the competitive carrier is responsible for compensating the transit provider for traffic originated by both the competitive carrier and the incumbent carrier. In the CMRS Providers' opinion, Embarq's request and the conclusion of the *RAO* which required the CMRS Providers to pay the transit costs for landline originated traffic are in violation of federal law for the reasons previously cited in their initial objections.

ALLIANCE: The Alliance did not file reply comments.

EMBARQ: Embarq reiterated its request that the Commission clarify that the competitive carrier is responsible for compensating the transit provider for traffic originated by both the competitive carrier and the incumbent carrier.

PUBLIC STAFF: The Public Staff did not file any reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth echoed the CMRS Providers' arguments and requested that the Commission reconsider its decision with regard to this issue.

VERIZON WIRELESS: Verizon Wireless took issue with the Public Staff's analysis regarding the establishment of a "virtual network" where traffic was originated on the landline network and terminated on the mobile carrier's network. According to Verizon Wireless, the Public Staff's virtual network concept in this instance absolves the RLECs of any financial responsibility for transit charges for any traffic that they originate and choose to route indirectly to the CMRS Providers. Verizon Wireless agreed that the Public Staff analysis regarding the establishment of a virtual network and the assignment of financial responsibility for transit costs to the CMRS Providers for CMRS to landline originated traffic was correct.

DISCUSSION

The Commission concluded in Finding of Fact No. 2 that the RLECs are financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of completing the call beyond the POI, but they are not responsible for payment of transit charges assessed by third parties, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI. The RLECs and their supporters have championed the position that the CMRS Providers are responsible for payment of the transit charges because they have chosen to interconnect indirectly with the RLECs network and, as a result, the CMRS Providers can only choose to interconnect at any technically feasible location on the RLECs' network. By contrast, the CMRS Providers and their supporters have vigorously argued that, in the case of indirect interconnection, the CMRS Providers can choose the locations of POIs and the RLECs are responsible for paying the transit costs for calls that originate within the RLECs network to the CMRS Providers' POI. Both have asserted that the result that they have advocated is mandated by statute, regulation or equitable considerations.

In the midst of all these arguments, there is but one point upon which all parties can either explicitly or implicitly agree. The parties agree, either explicitly or implicitly, that the "determination of where the POI is located in the cases of indirect interconnection, in effect, determines which carrier pays the transit charge for landline originated traffic" in the first instance. See CMRS Providers' Post Hearing Brief, p. 6. Stated differently, this Commission held that "the key to a proper assignment of costs, at least in the first instance, is determining the location of the POI." P-118, Sub 130, *Alltel RAO*, p. 13. As reflected in the prior discussion of Issue No. 1, the Commission has determined that it is appropriate for there to be but one POI located on the RLEC's network when the parties are indirectly interconnected. Accordingly, the location of the POI on the RLEC's network dictates that the RLECs are technically and financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for paying transit charges directly to the third party transit provider.

The CMRS Providers strenuously disagree with this conclusion. They argue, in effect, that the RLECs are responsible for paying the third party transit costs directly to the transit provider in addition to paying reciprocal compensation to the terminating carrier for completing the call even if the POI is located on the RLEC's network. This argument has obvious shortcomings, including the fact that the CMRS Providers' argument presumes that there is a legal requirement that the RLECs pay transit costs *separate and apart from reciprocal compensation.*

As the RLECs point out in their initial comments, neither the Act nor the FCC's regulations require an originating ILEC to be responsible for paying charges assessed by a third party for off network transit of that portion of traffic which is carried by the third party.

Specifically, the FCC determined that its rules do not address third-party transit service. See, *In the Matter of Petition of WorldCom, Inc. Regarding Interconnection Disputes with Verizon Virginia Inc.*, 17 FCC Rcd. 27039, 27100 Para 115 (2002) (*WorldCom Petition*). In affirming Verizon Virginia's assessment of transit charges on competitive carriers, the FCC noted an absence of FCC rules specifically governing transit service. The FCC reaffirmed this position on page 60, paragraph 132 of its *Intercarrier Compensation Further NPRM* when it stated: "The reciprocal compensation provisions of the Act address the exchange of traffic between two carriers, but do not explicitly address the intercarrier compensation to be paid to a transit provider for carrying section 251(b)(5) traffic." *Intercarrier Compensation Further NPRM*, CC Docket No. 01-92, FCC 05-33, p. 60, para. 132. Moreover, 47 C.F.R. 51.701(e) provides that "a reciprocal compensation arrangement between <u>two carriers</u> is one in which <u>each</u> of the <u>two carriers</u> receives compensation from the other carrier for the transport and termination on <u>each carrier's network facilities</u> of telecommunications traffic that originates on the network facilities of the other carrier." (Emphasis added.).

The CMRS Providers also argue with some vigor that FCC Rule 51.701(b)(2) requires reciprocal compensation to be paid for telecommunications traffic exchanged between a LEC and a CMRS Provider that, at the beginning of the call, originates and terminates within the same MTA. The CMRS Providers argued further that Section 51.703(b) of those same rules states that a LEC may not assess charges on any other telecommunications carrier for telecommunications traffic that originates on the LEC's network. Finally, the CMRS Providers argue that the RLECs' duty to pay reciprocal compensation which <u>may</u> have a component of transit costs includes a concomitant duty to pay a separate fee for transit costs to a third party in addition to the payment of reciprocal compensation.

Neither the RLECs, their allies, nor the *RAO* dispute the merits of those first two propositions. That is, the RLECs agree that FCC Rules require reciprocal compensation to be paid for telecommunications traffic exchanged between a LEC and a CMRS Provider that, at the beginning of the call, originates and terminates within the same MTA and that a LEC may not assess charges on any other telecommunications carrier for telecommunications traffic that originates on the LEC's network. Further, the RLECs agree that they are obligated to pay reciprocal compensation to the CMRS Providers for terminating RLEC-originated local traffic. See RLECs Comments April 25, 2008, p. 8. However, the RLECs strongly disagreed with the CMRS Providers' attempts to conflate the RLECs' duty to pay reciprocal compensation, which <u>may</u> include a component intended to compensate the terminating carrier for the payment of transit charges, into a duty requiring the RLECs to pay a separate fee for transit costs to a third party in addition to paying reciprocal compensation. The *RAO* concurred with the RLECs' position and rejected the CMRS Providers' attempt to conflate a duty to pay reciprocal compensation into a concomitant duty to pay a separate fee to the third party transit provider in addition to the payment of reciprocal compensation.

In the *RAO*, the Commission deduced from the FCC's regulations that reciprocal compensation covers the terminating carrier's expense for both transport and termination of the RLEC originated local traffic and that transit costs can be a component of the terminating carrier's transport expense. Further, the Commission noted that reciprocal compensation is designed to compensate <u>both</u> parties for the additional costs of terminating local calls to each other's customers through symmetrical rates based on the relevant LEC's cost study or a default proxy. See, In re *Implementation of Local Competition Provisions in the Telecommunications Act of 1996*, CC Docket No. 96-98 and CC Docket No. 95-185 (August 8, 1996), (*Local Interconnection Order*,) Para. 1085; 47 C.F.R. 51.711(a). Furthermore, the *RAO* held that, pursuant to 47 C.F.R. 51.711(b)[1], the CMRS Providers could petition the Commission to establish asymmetrical rates if the CMRS Providers believe that the symmetrical compensation rates that would otherwise apply did not suffice to fairly and completely compensate the CMRS Providers for the cost of terminating RLEC-originated traffic, including the transit fees assessed by a third party. Under this approach, third party transit fees should be recovered through the payment of reciprocal compensation.

The CMRS Providers argue against the recovery mechanism provided in 47 C.F.R. 51.711(b), and, instead, expressed a preference for requiring the RLECs to pay the transit costs associated with RLEC-originated traffic directly to the third party transit provider in the first instance in addition to paying reciprocal compensation to the CMRS Providers. The CMRS Providers were especially critical of the requirement that "the CMRS Providers must initially pay the transit charge for landline traffic, then seek reimbursement from the RLECs through reciprocal compensation rates" and the suggestion that the CMRS Providers must produce a forward looking cost study to seek reimbursement for the transit rates that they are required to pay to the third party through the payment of reciprocal compensation. According to the CMRS Providers, the transit charges are essentially line items that should be passed through to the RLECs. In the opinion of the CMRS Providers, it makes more economic sense for the originating party to pay the transit charge rather than for the terminating carrier to pay the transit charge and then seeking reimbursement from the originating carrier.

The CMRS Providers cited the Fourth Circuit case of *MCI Metro v. BellSouth*, 352 F.3d 872 (4th Cir. 2003) (*MCI Metro*), the *Atlas* case from the Tenth Circuit and the *WWC License v. Public Service Commission*, 459 F. 3d 880 (8^{th} Cir. 2006)[2] (*WWC License*) as support for these contentions. The Commission has closely read each case and notes that none of the cases cited by the CMRS Providers expressly states that the originating carrier has an obligation to pay a transit charge assessed by a third party carrier in addition to paying reciprocal compensation. In fact, in the *Atlas* case, the Tenth Circuit, consistent with the approach adopted in the RAO, held that the originating rural carrier had an obligation to compensate *the terminating CMRS carrier* under the *reciprocal compensation* regime for traffic transported to the POI of the CMRS Provider. *Atlas*, 400 F.3d 1256 at p. 1267(2005). Similarly, in the *MCI Metro* decision, the Fourth Circuit invalidated a Commission decision that required the payment of charges assessed by the ILEC against a CLP intended to compensate the ILEC for costs incurred on the ILEC's side of the POI, a result that is very different from the assignment of responsibility for transit charges assessed for use of facilities located beyond the POI of the type at issue here. Finally, the *WWC License* decision assumes the existence of a distant POI on the basis of *Atlas*, a

[1] Under 47 C.F.R. 51.711(b) "[a] state commission may establish asymmetrical rates for transport and termination of local telecommunications traffic if the carrier other than the incumbent LEC...proves to the state commission on the basis of a cost study using forward-looking economics cost based methodology...that the forward-looking costs for a network efficiently configured and operated by the carrier other than the incumbent LEC...exceed the costs incurred by the incumbent LEC...and, consequently, that such a higher rate is justified."

[2] The cost allocation in each of these cases is determined by the location of the POI[s].

decision which the Commission as already concluded to not be controlling here. As a result, all of the decisions upon which the CMRS Providers reply are readily distinguishable from the present situation.

With regard to the CMRS Providers' contention that transit charges on RLEC-originated traffic are essentially line items that should be passed through by the RLECs and that it makes more economic sense for the originating party to pay the transit charge rather than for the terminating carrier to pay the charge and seek reimbursement from the originating carrier, the Commission notes that Congress and the FCC have adopted a comprehensive scheme to encourage a robust and competitive telecommunications market. As a part of that scheme, Congress and the FCC have adopted a reciprocal compensation regimen to compensate two carriers for the transport and termination of local traffic. This scheme presumes that the symmetrical reciprocal compensation rate will capture all the individual elements and costs necessary to originate and terminate a call and will thus fairly and fully compensate both parties for calls originated and terminated on their individual networks. Furthermore, if any carrier believes that the reciprocal compensation rate does not adequately capture all relevant call termination costs such that it does not receive adequate compensation through payment of the symmetrical reciprocal compensation rate, that carrier may petition the Commission to establish an asymmetrical reciprocal compensation rate which will allow the carrier to fully recover its costs of terminating a particular call. Adoption of the approach recommended by the CMRS Providers is not consistent with the basic approach adopted by Congress and the FCC. As a result, given our decision with respect to the number and location of the POI, the Commission believes that FCC rules and federal law require the CMRS Providers to: (1) first pay the transit charge and thereafter seek reimbursement of those charges from the originating carrier through reciprocal compensation[1] and (2) produce a forward looking cost study to justify any deviation from the symmetrical reciprocal compensation rate necessary to permit them to recover the transit charges that they have paid from the originating carrier.[2]

Thus, even if one were to assume *arguendo* that it does indeed make more economic sense for the originating carrier to pay the transit provider directly as the CMRS Providers propose, this Commission is constrained in our actions by the Telecommunications Act, the rules adopted by the FCC and the decisions of the federal courts interpreting the Act and FCC rules. Given the Commission's decision with respect to the number and location of the POI, those decisions and rules require the CMRS Providers to: (1) first pay the transit charge and thereafter seek reimbursement of those charges from the originating carrier through reciprocal compensation and, (2) produce a forward looking cost study to justify any proposed deviation from the symmetrical reciprocal compensation rate in order that they can recover the transit

[1] *Texcom Inc. v. Bell Atlantic Corp.*, 17 FCC 6275(2002) states that "the Commission and the Bureau have made clear that a terminating carrier may seek reimbursement of these [transiting] costs from originating carriers through reciprocal compensation." 17 F.C.C.R. 15135, 15137 n. 13. See also *TSR Wireless LLC v. U.S. West Communications, Inc.*, 15 F.C.C.R. 11166, 11177, n. 70(2000), aff'd sub nom *Qwest v. FCC*, 252 F.3d 462(D.C. Cir. 2001).

[2] 47 CFR 51.711(b).

charges that they have been paid to a third party.[1] This is the law and the Commission must abide by it.

Even if this was not the law, the Commission would be hesitant to require the RLECs to treat transit costs essentially as a line item which is passed through without challenge or review. As the RLECs have pointed out, these transiting arrangements are a legacy, in many instances, of past negotiations between the CMRS Providers and tandem operators with which the CMRS Providers were affiliated. Initial Comments of the RLECs, April 25, 2008, p. 8. The RLECs were often not included in these discussions. Id. See *Intercarrier Compensation Further NPRM,* CC Docket No. 01-92, FCC 05-33, p. 56-57, para. 123, n. 348. As a result, there is a risk that the CMRS Providers may be unjustifiably rewarded and the RLECs financially harmed because of the CMRS Providers' failure to negotiate a more reasonable rate in the event that the approach advocated by the CMRS Providers was to be adopted here.

Further, the Commission notes that the CMRS Providers' rates, financing and network configurations are not subject to regulatory review by a state commission under the current federal regulatory scheme. 47 U.S.C. 332(c)(1). The Commission, thus, has no way to tell if the symmetrical compensation rates, which are based upon the costs of the RLECs' networks, are fully compensatory, partially compensatory or so high that they are providing the CMRS Providers with a windfall as the RLECs and their allies allege. Under these circumstances, the only way that the Commission can determine the CMRS Providers' actual costs of originating and terminating a call and ascertain if those actual costs "exceed the costs incurred by the incumbent LEC..., and, consequently, that such a higher rate is justified" to include transit costs is in the event that the CMRS Providers were to *voluntarily* submit such information for Commission review as part of an effort to prove that they are entitled asymmetrical reciprocal compensation. 47 C.F.R. 711(b).

In the Commission's view, it would be inherently unfair to require the RLECs to pay the transiting charge as a line item, as the CMRS Providers propose, without allowing for some opportunity for review to determine the actual costs that the CMRS Providers incur to originate and terminate a call or to determine if the transiting costs or a portion thereof are indeed being recovered in the symmetrical reciprocal compensation rate. Only through such a comparative review could the Commission determine if the reciprocal compensation rates were fully compensatory to both parties, instead of being compensatory to one party while providing a windfall to another. And, finally, only through such a comparative review could the Commission avoid a situation where the RLECs would be required to pay twice for the same transit service, i.e., once to the CMRS Providers for transiting costs that are captured in the reciprocal compensation rates and again in the form of a separate payment to the third party transit provider.

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[1] See *Intercarrier Compensation Further NPRM p. 34, paras. 91-92,* where the FCC discusses the reciprocal compensation regime for originating and terminating traffic when there are direct and indirect interconnections between a LEC and CMRS Providers. The FCC states: "Under both types of LEC-CMRS interconnection, the LEC receives forward looking economic costs-(FLEC-) based reciprocal compensation for the LEC's additional costs of terminating CMRS-originated calls. The CMRS carrier, on the other hand, is compensated at the LEC's FLEC-based rate, which is the presumptive proxy for the CMRS carrier's own termination costs *unless the CMRS carrier submits a forward-looking economic study to rebut this presumptive symmetrical rate."* See Also *Local Competition Order, paras. 1085-1089.*

Finally, in comments, Embarq, a non-party to this proceeding, noted that, while the *RAO* specified that the RLECs are not responsible for transit charges beyond the POI based upon the competitive carrier's use of a third party's network facilities, the *RAO* did not specify that the competitive carrier is obligated to pay the transit provider for the use of its network. Embarq thereafter requested that the Commission clarify that the competitive carrier is responsible for compensating the transit provider for traffic originated by both the competitive carrier and the incumbent carrier. As we have stated previously, there is a lack of FCC rules governing transit issues. The absence of such authority has made our task in resolving the issues presented by this proceeding more difficult. The FCC does have a pending docket in which this and other intercarrier compensation issues are supposed to be addressed. Given the fact that this issue is before the FCC and that fact that a decision on the issue raised by Embarq is not necessary to fully dispose of this case, the Commission, in its discretion, declines to issue the ruling requested at this time.

CONCLUSIONS

The Commission's conclusion that "[t]he RLECs are technically and financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for transit charges, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI" should be affirmed.

<u>FINDING OF FACT NO. 4 (ISSUE NO. 4 - MATRIX ISSUE NO. 6A):</u> Must the RLECs' cost studies and rates comply with Section 252(d) of the Act and related FCC regulations?

INITIAL COMMISSION DECISION

The Commission concluded that, "[b]ecause the Commission modified the reciprocal compensation requirements of Section 251(b)(5) of the Act in Docket No. P-100, Sub 159; the RLECs are not required to perform strict TELRIC studies to establish reciprocal compensation rates, and the rates proposed for reciprocal compensation do not have to comply with all of the requirements set forth in Section 252(d) of the Act and related FCC rules."

MOTIONS FOR RECONSDERATION

MEBTEL: MebTel did not object to this Finding of Fact.

RANDOLPH: Randolph did not object to this Finding of Fact.

CMRS PROVIDERS: The CMRS Providers objected to this Finding of Fact. The CMRS Providers asserted that Section 251(f)(2) of the Act gives the Commission authority to suspend or modify the subsection 251(b) duty to establish reciprocal compensation arrangements. If that obligation is suspended, then an RLEC is not required to enter into reciprocal compensation arrangements, and the RLEC is not required to establish its reciprocal compensation rates through the use of the TELRIC study required by the pricing standards set forth in Section 252(d)(2). A state commission does not, however, have the authority under

Section 252(f)(2) to suspend the pricing standards set forth in Section 251(d)(2). Thus, if an RLEC does not seek to suspend the Section 251(b)(5) reciprocal compensation obligations, the RLEC must establish its transport and termination rates through the use of a TELRIC study as required in Section 252(d)(2).

NON-PARTY COMMENTS

EMBARQ: Embarq did not comment on this Finding of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not comment on this Finding of Fact.

VERIZON WIRELESS: Verizon Wireless did not comment on this Finding of Fact.

INITIAL COMMENTS

RLECs: The RLECs argued that the modification of an RLEC obligation to produce a TELRIC compliant cost study is an essential element of the process necessary to establish reciprocal compensation and that the Commission has the authority under Section 251(f)(2) to modify the requirement that transport and termination rates be established based upon a TELRIC compliant study.

CMRS PROVIDERS: The CMRS Providers incorporated their prior arguments regarding this Finding of Fact by reference.

ALLIANCE: The Alliance did not file comments on the Finding of Fact.

EMBARQ: Embarq did not file comments on the Finding of Fact.

PUBLIC STAFF: The Public Staff first noted that this issue has been decided previously by the Commission against the CMRS Providers in Docket No. P-100, Sub 159 and thereafter stated that the Commission has the authority under Section 251(f)(2) to modify the requirement that the reciprocal compensation rates for transport and termination be established based upon a TELRIC compliant study in accordance with the prior Commission decision.

REPLY COMMENTS

RLECs: The RLECs did not file any reply comments on this Finding of Fact.

CMRS PROVIDERS: The CMRS Providers did not file reply comments on this Finding of Fact.

ALLIANCE: The Alliance did not file reply comments on this Finding of Fact.

EMBARQ: Embarq did not file reply comments on this Finding of Fact.

PUBLIC STAFF: The Public Staff did not file reply comments on this Finding of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not file reply comments on this Finding of Fact.

VERIZON WIRELESS: Verizon Wireless did not file reply comments on this Finding of Fact.

DISCUSSION

In Docket No. P-100, Sub 159, the Commission summarized the CMRS Providers' argument as follows:

> (1) that the Commission can neither "modify" nor "suspend" the FCC's TELRIC pricing methodology because, under Section 251(f)(2), the Commission is granted authority to modify or suspend only certain of the obligations established by Section 251(b) or (c), and the Section 252(d)(2) TELRIC pricing standards are not among those obligations . . .
>
> With respect to the first argument regarding modification or suspension of the obligations under Section 251(b) and (c), the CMRS providers pointed out that Section 252(d)(2)(A) sets out pricing standards applicable to Section 251(b)(5) reciprocal compensation arrangements, upon which the FCC elaborated by rule. The gist of the CMRS Providers' argument is that Section 251(f)(2) by its terms allows a suspension or modification only as to the obligations under subsection (b) and (c) and not the pricing standards of Section 252(d)(2), which appear in an entirely different section.
>
> *Modification Order pp. 7-8.*

The full Commission rejected the CMRS Providers' position in that docket. AT&T Mobility's predecessor in interest, Cingular Wireless, was a member of the CMRS Providers and a party in that docket.[1] The CMRS Providers did not appeal.

In the case in chief and again in the objections filed to the RAO in this case, AT&T Mobility, joined by Alltel Wireless, makes essentially the same argument that was made by the larger group of CMRS Providers in Docket No. P-100, Sub 159. Now, as then, the CMRS Providers' argument rests entirely upon the premise that the Act does not allow the RLECs to obtain a suspension or modification of the provisions of Section 252(d) and related FCC regulations and, at the same time, allow the RLECs to enforce Section 251(b)(5) obligations against the CMRS Providers without suspension or modification.

The Commission has twice rejected this argument: once in the *Modification Order* and again in the *RAO*, in which the Commission stated:

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[1] In the October 4, 2005, *Order Seeking Comments* in Docket P-100, Sub 159, the Commission ordered that Alltel Wireless be given notice. Alltel did not file comments or formally participate in the docket.

In our view, this was and is a logical step that follows from the Act's express grant of authority allowing RLECs to apply to the Commission to opt out of costly TELRIC based studies to determine reciprocal compensation rates. We do not believe that Congress intended to allow the RLECs to opt out of undertaking the TELRIC study only to then require them to engage in a costly "TELRIC type" study to establish reciprocal compensation rates if they choose to modify rather than to suspend their obligations altogether under Section 251(b)(5) of the Act as the CMRS Providers here propose. That, in our view, would be illogical and would violate Congress' expressed intent. We decline to adopt such an interpretation. In light of this belief and for the reasons previously set forth, we conclude that the rates are not required to comply with Section 252(d) and the related FCC regulations."

RAO p. 30.

This analysis was sound then, and it is sound now. In the absence of directions to the contrary from the appropriate federal authorities, the CMRS Providers' arguments should again be rejected and the conclusions of the *RAO* on this issue affirmed.

CONCLUSIONS

Because the Commission modified the reciprocal compensation requirements of Section 251(b)(5) of the Act in Docket No. P-100, Sub 159, the RLECs are not required to perform strict TELRIC studies to establish reciprocal compensation rates, and the rates proposed for reciprocal compensation do not have to comply with all of the requirements set forth in Section 252(d) of the Act and related FCC rules.

FINDING OF FACT NO. 8 (ISSUE NO. 8 – MATRIX ISSUE NO. 18): What total switch investment per line should be used for MebTel's cost study?

FINDING OF FACT NO. 27 (ISSUE NO. 29 – MATRIX ISSUE NO. 30): Is MebTel's alternative cost study consistent with the alternative cost study Guidelines established by the Commission in Docket No. P-100, Sub 159?

INITIAL COMMISSION DECISION

FINDING OF FACT NO. 8: The Commission concluded that it was not appropriate to alter MebTel's proposed switch investment per line as proposed by the CMRS Providers. However, in Finding of Fact No. 7, the Commission excluded the investment in the Mebane DMS switch from MebTel's cost study. Therefore, the Commission agreed that MebTel's proposed total switch investment per line of $458 should be used, however, the figure should be adjusted based on the Commission's conclusions concerning usage sensitive switching costs discussed in Finding of Fact No. 10.

FINDING OF FACT NO. 27: The Commission concluded that, in the Evidence and Conclusions for Findings of Fact Nos. 7 through 10, the Commission addressed the CMRS

Providers' objections to the alternative cost study filed by MebTel. The Commission noted that, in its conclusions for Findings of Fact Nos. 7 through 10, the Commission indicated what adjustments or changes to the study are required to meet all of the Guidelines established in Docket No. P-100, Sub 159. The Commission concluded that, once these adjustments are made, MebTel's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel did not object to this Finding of Fact[1].

RANDOLPH: Randolph did not object to this Finding of Fact.

CMRS PROVIDERS: The CMRS Providers objected to this Finding of Fact and stated that the Commission's conclusions inappropriately allow MebTel to reflect historical, booked switching investment rather than the current cost to purchase and install new switches in its alternative cost study. The CMRS Providers maintained that the *RAO* adopts a switch investment for MebTel of $458 per line, subject to the removal of non-usage-sensitive investments and costs, and it is uncontroverted that this figure is based upon MebTel's embedded costs. The CMRS Providers contended that the cost to purchase and install new switches has declined significantly since MebTel's embedded investments were incurred. The CMRS Providers asserted that, as a consequence, the switching component of MebTel's costs, even after non-usage sensitive costs are removed, is still impermissibly high and does not comply with Guideline 2 of the Commission's *Modification Order*[2]. The CMRS Providers argued that it is practicable for MebTel to adjust its embedded switching investment to make it more representative of forward-looking costs. The CMRS Providers maintained that to not do so is to ignore the uncontroverted evidence that switching investments have declined over time; it would be analogous to a leasing company setting the current monthly rental for a personal computer based on the cost to purchase a computer 10 to 15 years ago – when the cost of personal computers has dropped substantially. The CMRS Providers stated that, in a competitive market, there would be no demand at such rental rates.

The CMRS Providers asserted that there are at least two simple and practicable ways that MebTel's switching costs can be made forward-looking. The CMRS Providers noted that, first, MebTel's embedded switching investment can simply be modified to take into account the drop in switch prices over time. The CMRS Providers stated that, second, MebTel's forward-looking switching costs can be based upon the FCC's switch price data, also reduced for the drop in switch prices, as proposed by witness Conwell. The CMRS Providers argued that both of these methods are easy and practicable. The CMRS Providers maintained that a failure to require

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[1] Although MebTel represented that its Objections only relate to Finding of Fact No. 10, MebTel noted that its cost study showed total central office equipment (COE) investment of $10,451,065, which consisted of $9,322,471 in direct investment in three switches plus another $1.1 million investment in land, buildings, and other equipment necessary to support operations of these switches. The Commission did not recognize the $1.1 million investment in land, buildings, and other equipment in its *RAO*.

[2] Guideline 2 of the *Modification Order* states that "[t]he cost data may be a surrogate of the company's cost, but should be forward looking and reflect an efficient network to the extent practicable."

MebTel to use one of these methods would constitute a violation not only of the Act and FCC rules, but also of the *Modification Order* itself.

The CMRS Providers noted that a practicable way to make MebTel's switching costs forward-looking is simply to reduce the switch investment of $458 per line to $403 to reflect the 12 percent decline in switch reproduction costs from 1999 to the present (based on the AUS Price Index). The CMRS Providers maintained that that $403 switch investment would then be multiplied by the 38 percent to produce a forward-looking and usage-sensitive figure of $153 per line.

The CMRS Providers further noted that witness Conwell computed MebTel's forward-looking switching investment ($143 per line) based upon data derived by the FCC in 1999, subject to a 12 percent reduction based upon the decline of switching costs since 1999 – as shown by the AUS Price Index, a recognized industry authority.

The CMRS Providers also criticized the Commission's reasons for rejecting the use of the FCC switch cost data outlined in the *RAO*. First, the CMRS Providers detailed the calculation used to determine how the $143 figure proposed by witness Conwell was calculated; the Commission stated in the *RAO* that it had been unable to determine how that figure was calculated. The CMRS Providers asserted that the Commission overlooked the remaining relevant portion of witness Conwell's testimony, which pointed out that the Mebane switch serves 11,417 lines, 77 percent of MebTel's total lines. The CMRS Providers noted that the Gatewood switch serves 1,522 lines (10 percent) and the Milton switch serves 1,857 lines (13 percent). The CMRS Providers argued that it would be inappropriate to determine an average switch investment per line by simply adding the investment per line of each switch and then dividing by three. The CMRS Providers maintained that such a method would be appropriate only if each switch served approximately the same number of lines. The CMRS Providers noted that, since the Mebane switch serves 77 percent of the total MebTel lines, the per line switch investment must be based on a weighted average. The CMRS Providers noted that the steps in the calculation are as follows:

($114 x 77 percent) + ($353 x 10 percent) + ($153 x 13 percent) = $143

The CMRS Providers stated that for the *RAO* to reject witness Conwell's proposed switch investment per line on the grounds that the Commission did not understand the investment calculation is not a valid criticism of the testimony, is not supported by a rational basis, and is therefore arbitrary and capricious.

The CMRS Providers further asserted that, in rejecting witness Conwell's proposed switch investment for MebTel of $143 per line, the *RAO* rejected the FCC switch cost data upon which that proposed investment was based, because "the *FCC's USF Inputs Order* pertains to nonrural carriers, which will necessarily have different switch costs from rural carriers such as MebTel." The CMRS Providers noted that the *RAO* acknowledged that the FCC used a small sample of information from rural carriers in estimating switch costs in its *USF Inputs Order*. The CMRS Providers argued that this assertion is contrary to the FCC's *USF Inputs* Order, which describes the method used by the FCC to develop its switch cost data:

> The sample that we use to estimate switch costs includes 1,085 observations. The same contains 946 observations selected from the depreciation data, which provide information on the costs of purchasing and installing switches gathered from 20 states. All observations in the depreciation data set are for switches with 1,000 lines or more. In order to better estimate the cost of small switches, we augmented the depreciation data set by adding data from RUS. The RUS sample contains 139 observations which provide information from across the nation on the costs of small switches purchased and installed by rural carriers. Over 80 percent of the observations of the observations of switch costs in the RUS data set measure the costs for switches with 1,000 lines of capacity of less. [Paragraph 299]

The CMRS Providers noted that almost 13 percent (139/1,085 = 12.8 percent) of the data was taken from RUS records to better estimate the cost of small switches. The CMRS Providers stated that, in the context of the FCC study, a small switch was defined as one serving less than 1,000 access lines. The CMRS Providers maintained that, of the total of 1,085 switches surveyed by the FCC, 973 or 90 percent (973/1,085) involved switches serving over 1,000 access lines, the category in which MebTel's switches fall. The CMRS Providers asserted that, in other words, MebTel's switches would not be considered small switches in the development of the FCC's switch cost data.

The CMRS Providers argued that for the *RAO* to hold that the FCC data pertains to non-rural carriers which will necessarily have different switching costs from carriers such as MebTel is to ignore the uncontroverted fact that MebTel's three switches all fall into the category (switches serving over 1,000 access lines) represented by almost 90 percent of the FCC data. The CMRS Providers noted that the same is true for Randolph, which operates a single switch serving 4,700 access lines. The CMRS Provider asserted that failing to consider these facts was arbitrary and capricious.

The CMRS Providers noted that the *RAO*'s third reason for rejecting witness Conwell's testimony is that the FCC's switch cost data does not capture the costs of functionalities mandated by the FCC since 1999. The CMRS Providers asserted that the *RAO* does not discuss the functionalities it might have in mind, but it does agree with the Public Staff on this point.

The CMRS Providers maintained that the Public Staff's proposed order claims that the FCC switch cost data does not reflect functionalities that have been mandated by the FCC since the time the FCC collected the switch cost data and references page 80 of Volume II of the transcript, a section from the direct testimony of Randolph witness Schoonmaker that does not discuss the FCC switch cost data. The CMRS Providers noted that, however, on page 81, witness Schoonmaker states:

> The FCC has required a number of functionalities to be added to switches since that time, intraLATA dialing parity, interchangeable NXX codes and CALEA [the Commission on Accreditation for Law Enforcement Agencies, Inc.] capabilities among them.

The CMRS Providers asserted that it appears then that the *RAO* has rejected the FCC switch cost data because it does not contain the cost of switch upgrades for, *inter alia*, intraLATA dialing parity, interchangeable NXX codes, and CALEA capabilities.

The CMRS Providers noted that, in determining its switch cost data, the FCC expressly excluded upgrade costs:

> We believe that this restriction will eliminate switches whose book values contain a significant amount of upgrade costs, and recognizes that, when ordering new switches, carriers typically order equipment designed to meet short-run demand.

The CMRS Providers asserted that, under federal law, which the Commission is required to apply in this case, the costs of switch software upgrades cannot be included in, or recovered from, transport and termination rates. The CMRS Providers noted that MebTel's transport and termination cost has been reduced from $0.0140 to $0.0051 per minute based on the adjustments required in the *RAO*; the chief remaining issue is the switch investment per line.

The CMRS Providers asserted that the revised MebTel rate of $0.0051 per minute reflects an embedded switch investment of $458 per line, reduced by 62 percent for the non-usage sensitive component to produce an investment of $174 per line. The CMRS Providers argued that the record evidence is clear and uncontroverted that MebTel's forward-looking switch investment per line must be lower than this figure. The CMRS Providers noted that simply reducing this figure by 12 percent produces an investment figure of $153 per line; carrying this figure forward in MebTel's cost study results in a switching cost of $0.0030 per minute and overall transport and termination rate of $0.0046 per minute. The CMRS Providers maintained that this rate is greater than the rate that would result using witness Conwell's forward-looking switching cost that was based on FCC switch cost data, so it should be considered the maximum allowable rate for MebTel.

NON-PARTY COMMENTS

EMBARQ: Embarq did not comment on these Findings of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not comment on these Findings of Fact.

VERIZON WIRELESS: Verizon Wireless did not comment on these Findings of Fact.

INITIAL COMMENTS

RLECs: The RLECs stated that the Commission is authorized to modify the application of the FCC's TELRIC requirements to the RLECs. The RLECs noted that, in their Objections, the CMRS Providers effectively challenge all of the Commission's findings concerning MebTel's alternative cost study. The RLECs asserted that, at the outset, they rehash their previously presented arguments as to the meaning and interpretation of the Commission's *Modification Order* and the alternative cost study guidelines adopted by the Commission therein. The RLECs maintained that the CMRS Providers specifically contend, despite the clear reach of the *Modification Order* and the Commission's express authority under Section 251(f)(2), that reciprocal compensation for the RLECs must be established in compliance with the FCC's TELRIC requirements. The RLECs noted that, in fact, they present this argument both in the context of their specific objections to the MebTel and Randolph cost studies, and again in a separate objection based on Section 252(d). The RLECs stated that the result urged by the CMRS Providers on this point is absurd. The RLECs maintained that, fairly summarized, the CMRS Providers depict the Commission's *Modification Order* as having said to the RLEC's, "we excuse you from any requirement to perform cost studies that comply with TELRIC, however, your costs must be determined based on TELRIC." The RLECs argued that the Commission properly rejected these same arguments the first time they were presented by the CMRS Providers.

The RLECs stated that Section 251(b)(5) of the Act imposes the "duty to establish reciprocal compensation arrangements." The RLECs maintained that the CMRS Providers, in their Objections, again present their argument that Section 252(d) of the Act establishes the pricing standards for reciprocal compensation and that the Commission had no authority to modify those pricing standards. The RLECs noted that what the Commission did, in fact, was to modify the cost study obligations of the RLECs, as it was able to under Section 251(f)(2). The RLECs asserted that cost studies play a central role in the process required "to establish reciprocal compensation arrangements."

The RLECs argued that the question raised here again is the extent of the Commission's authority under Section 251(f)(2) to modify the RLECs' duty to establish reciprocal compensation. The RLECs opined that, if modification of any RLEC obligation to produce a TELRIC compliant cost study would be an essential requirement of the process necessary to establish reciprocal compensation (which it is) and if the Commission has the authority under Section 251(f)(2) to modify such a requirement (which it does), then this modification was lawful and proper.

The RLECs noted that the Commission will recall that the RLECs' Petition in Docket P-100, Sub 159 was prompted by the CMRS Providers' demand that each RLEC provide a TELRIC-compliant cost study. The RLECs stated that, in the *Modification Order*, the Commission did not suspend the RLECs' obligations to establish reciprocal compensation arrangements; it simply modified any requirement to produce TELRIC-compliant cost studies as part of establishing such an arrangement, as it was authorized to do so under Section 251(f)(2).

The RLECs argued that the first reason to again reject these arguments is because it is clear that Section 251(f)(2) allows the Commission, as a state commission, to modify the application of TELRIC rules to the RLECs with regard to the production of TELRIC-compliant cost studies. The RLECs maintained that that, in fact, was what the Commission did in the *Modification Order*. The RLECs maintained that the unavoidable practical result of the ruling in that docket is that the RLECs are excused from having their reciprocal compensation rates determined based on TELRIC. The RLECs stated that, as the Commission recognized in the *RAO*, any other outcome would lead to the nonsensical result that the RLECs are allowed to produce alternative cost studies in accordance with the guidelines adopted in that docket, where the Commission expressly ruled that the RLECs did not have to comply with TELRIC for purposes of negotiation or arbitration, yet then be obligated to have their alternative cost studies adjusted to comply with TELRIC and have their reciprocal compensation rates based on TELRIC. The RLECs asserted that the result urged by the CMRS Providers would render the Commission's authority under Section 251(f)(2) meaningless.

The RLECs stated that, second, the FCC has expressly recognized that a state commission has the authority to suspend or modify the application of TELRIC rules to rural telephone companies, such as the RLECs. The RLECs noted that the FCC, in its *First Report and Order*, pointed out that certain requirements of the Act and FCC regulations, including TELRIC pricing rules, do not apply to a rural telephone company until its rural exemption has been terminated. The RLECs stated that, in addressing various provisions of the Act and its regulations, including its TELRIC rules, the FCC likewise repeatedly states that "certain small incumbent LECs are not subject to our rules under Section 251(f)(1) of the 1996 Act, unless otherwise determined by a state commission, and certain other small incumbent LECs may seek relief from their state commissions from our rules under Section 251(f)(2)." *First Report and Order*, 11 FCC Rcd 15499, Paragraphs 697, 706, 934, 1059, 1088. The RLECs maintained that this is precisely what the RLECs did in Docket P-100, Sub 159 – they sought relief from the application of the FCC's TELRIC rules under Section 251(f)(2) and that relief was granted by this Commission, as provided for by the Act and as contemplated by the FCC.

The RLECs noted that, third, the United States Supreme Court has recognized the FCC's acknowledgement that state commissions have the authority to suspend or modify the application of TELRIC rules to rural telephone companies.

> [A]s the FCC has acknowledged, the smallest, rural incumbent local-exchange carriers most likely to suffer immediately from the imposition of unduly low rates are expressly exempt from the TELRIC pricing rules under 47 U.S.C. § 251(f)(1), and other rural incumbents may obtain exemptions from the rules by applying to their state commissions under 251(f)(2). *Verizon Communications, Inc. v. F.C.C.*, 535 U.S. 467, 528 (2002) n.39 (internal citations omitted).

The RLECs asserted that the Supreme Court's language echoes the FCC's acknowledgement that neither the Act nor the FCC's regulations impose TELRIC pricing as an absolute requirement. The RLECs argued that the Supreme Court, like the FCC, also recognized this Commission's authority under Section 251(b)(5) to modify the RLECs' obligations with regard to TELRIC.

The RLECs maintained that these authorities refute the CMRS Providers' argument that Section 252(d) of the Act renders the Commission powerless to modify the application of TELRIC requirements to the RLECs under Section 251(f)(2). The RLECs opined that the Commission must, again, reject the CMRS Providers' argument that Section 252(d) requires the RLECs to provide TELRIC-compliant cost studies and have their rates set according to TELRIC when the Commission had previously granted modification of any such requirement in accordance with the Act.

The RLECs noted that the CMRS Providers challenge the Commission's ruling on Matrix Issue No. 18 (Finding of Fact No. 8) – which found that, subject to the adjustments provided for in the *RAO*, MebTel's alternative cost study complies with the Commission's alternative cost study guidelines. The RLECs noted that the CMRS Providers, in their Objections, present again their argument that the Commission should reject MebTel's alternative cost study because it includes some embedded cost data. The RLECs stated that the CMRS Providers now argue that the $0.0051 per minute rate which the *RAO* would produce for MebTel is too high. The RLECs asserted that it is, at best, ironic that the CMRS Providers seek to reduce the amount they would pay MebTel below $0.0051 per minute, when they pay much larger ILECs in North Carolina reciprocal compensation ranging from $0.015 to $0.0175 per minute.

The RLECs noted that the CMRS Providers advocate two adjustments to the Commission's findings with regard to reciprocal compensation for MebTel: they again advocate the further reduction of MebTel's switch investment based on an alleged decline in switch costs, and they also again argue that the Commission should use other switch cost data proposed by CMRS Providers witness Conwell. The RLECs maintained that, on the first point, the CMRS Providers again propose a 12 percent reduction of MebTel's switch investment; the Commission has already heard and rejected this very same argument.

The RLECs asserted that the CMRS Providers rehash their prior argument that switch costs have declined in recent years and that the Commission should further reduce MebTel's switch investment by 12 percent. The RLECs noted that witness Conwell contended that switch costs have declined 12 percent since 1999 based on information he found in an excerpt from the AUS Price Index, which was formerly known as the Turner Price Index.

The RLECs stated that, on this point, it should be noted that RLEC Conwell Cross Examination Exhibit 2 showed that switch prices have either been stable or have increased since January 2003. The RLECs maintained that that exhibit also actually shows an 8 percent decrease, instead of a 12 percent decrease. The RLECs noted that, further, witness Conwell is not familiar with how AUS compiled the Index, or the data sources used, or whether it included data for small, independent ILECs like Ellerbe, MebTel, and Randolph. The RLECs proposed that the Commission should again reject this argument, and the proposed reduction on the grounds that the proposed adjustment is not necessary, is contradicted by witness Conwell's own source, and is based on a source (the AUS Price Index) that utilized unknown purported cost data that was not shown to be applicable to the RLECs and is not verifiable, as required by alternative cost study Guideline 1.

The RLECs maintained that, second, the CMRS Providers also argue that the Commission should use data from the FCC's *USF Inputs Order* to establish MebTel's switch cost. The RLECs asserted that, like the immediately preceding argument, the Commission has also already heard and rejected this argument. The RLECs noted that witness Conwell advocated the use of cost data from the FCC's 1999 *USF Inputs Order*, which he wants the Commission to reduce by 12 percent, based on the AUS Price Index.

The RLECs stated that, in the *RAO*, the Commission noted that it could not understand the basis for witness Conwell's recommendation that the Commission conclude that MebTel's switch investment was $114 per line. The RLECs maintained that, as the Commission noted in the *RAO*, that figure stands in marked contrast to data found in Public Staff Conwell Cross Examination Exhibit 1, an excerpt from the FCC's ARMIS report showing switching investment and expense per access line for the largest ILECs in North Carolina thru April 2007. The RLECs noted that MebTel's alternative cost study shows total switching investment of $621 per line, which witness Conwell characterized as "extraordinarily high." The RLECs asserted that, in the *RAO*, the Commission removed the Mebane DMS switch from MebTel's cost study and found that MebTel's switch investment was $458 per line. The RLECs stated that the FCC's ARMIS report data for large North Carolina ILECs showed that BellSouth's switching investment per line in North Carolina ranged from $387 per line in 1999 to $551 per line in 2006. The RLECs further noted that the FCC's ARMIS report data for Verizon South showed that Verizon's switching investment per line in North Carolina ranged from $698 per line in 1999 to $1,005 per line in 2006. The RLECs argued that, obviously, BellSouth and Verizon much larger ILECs than MebTel or the other RLECs and that it is reasonable to conclude that MebTel's costs are not anywhere near as low as the $114 advocated by witness Conwell, which is slightly less than ¼ of the $458 per line investment found in the *RAO*.

The RLECs noted that the CMRS Providers go on to argue that the Commission cannot reject witness Conwell's calculation of MebTel's per line investment – even if it does not understand how witness Conwell developed it – contending that the Commission's analysis of witness Conwell's recommendation "is not valid criticism of the testimony, is not supported by a rational basis and is therefore arbitrary and capricious." The RLECs argued that this assertion manifests the arrogance with which the CMRS Providers embrace their own views of the evidence in these dockets. The RLECs maintained that, suffice it to say, there is abundant credible evidence that MebTel's switch investment is higher than the $114 per line figure advocated by witness Conwell. The RLECs asserted that, further, if the Commission cannot follow witness Conwell's calculations to the point that it can verify they are correct – and would not produce a result consistent with the Commission's alternative cost study guidelines – then there is certainly a rational basis for the Commission having rejected this proposed adjustment of MebTel's switch investment data.

The RLECs opined that the Commission rightly rejected the use of switch cost data from the FCC's 1999 *USF Inputs Order* for two reasons. The RLECs stated that, first, the data was not gathered for use in establishing reciprocal compensation for companies of any size, but was instead gathered for use in determining universal service support for non-rural LECs. The RLECs noted that, in fact, the vast majority of the data reflected in the *USF Inputs Order* relates to non-rural ILECs. The RLECs maintained that, second, the cost data witness Conwell extracts from the *USF Inputs Order* is not verifiable, as required by alternative cost study Guideline 1. The RLECs asserted that it is not possible for either the Commission or the RLECs to conduct any analysis of the basis for that cost data, as witness Conwell does not possess the underlying data and it is not accessible through the record.

The RLECs noted that the CMRS Providers argued that the switch cost data from the *USF Inputs Order* should have been used – stating that "failure to consider these facts was arbitrary and capricious." The RLECs asserted that if anything is clear from the *RAO*, it is that the Commission "considered" the CMRS Providers' evidence as to alternative sources of switch cost data and the CMRS Providers' arguments as to why their proposed alternative data should be utilized. The RLECs maintained that, having considered the data offered by the CMRS Providers and the CMRS Providers' arguments, the Commission rejected them. The RLECs opined that it was certainly enough for the Commission to consider this evidence, and there was no arbitrary and capricious action by the Commission in reaching the decisions that it did.

The RLECs stated that, with regard to the Commission's decisions on the two points the CMRS Providers now re-argue, it is to be noted that the Commission's findings on those and many other issues presented were consistent with the recommendations of the Public Staff, as set forth in the Public Staff's Proposed Order. The RLECs commented that, as the Commission well knows, the Public Staff is statutorily charged with representing the interest of the "using and consuming public." The RLECs asserted that, as such, the findings recommended by the Public Staff on those various issues are significant, as they represent the thinking of an advocate statutorily charged with acting in the public interest.

The RLECs noted that the CMRS Providers also criticize the Commission for having rejected the data selected by witness Conwell from the *USF Inputs Order* because the cost data in the *USF Inputs Order* does not reflect the cost of switch software upgrades required by the FCC since 1999. The RLECs stated that, in doing so, the Commission accepted the arguments of the Public Staff and the RLECs that these software upgrade costs were properly taken into account in determining an RLEC's switch costs. The RLECs argued that their costs for switch software upgrades to expand and upgrade the capabilities of existing switches are real costs. The RLECs maintained that, as the Public Staff noted, the record revealed that the FCC has required that a number of functionalities be added to ILEC switches since 1999.

The RLECs further noted that the CMRS Providers argued that consideration of upgrade costs is inconsistent with federal law. The RLECs noted that they base that argument on the *USF Inputs Order*. The RLECs maintained that, in compiling switch cost data for establishment of universal service support (which had nothing to do with establishing reciprocal compensation), the FCC decided not to use cost data on switches more than three years old. The RLECs commented that, as the FCC noted, this approach allowed it to "eliminate switches whose book values contain a significant amount of upgrade costs" (*USF Inputs Order* at Paragraph 315). The RLECs asserted that it is, at best, misleading to suggest that the FCC's ruling on how it would develop data for use in establishing a USF for non-rural carriers is "federal law, which the Commission is required to apply in this case," where the issues relate to reciprocal compensation. The RLECs stated that the FCC's 1999 ruling on how it would develop switch cost data for use in establishing universal service support is inapplicable here; the baseless assertion that the *USF Inputs Order* is applicable "federal law" is just another facet of the determined CMRS Providers effort to understate the RLECs' cost of terminating CMRS-originated traffic.

CMRS PROVIDERS: Since the CMRS Providers filed the initial objection on this issue, they did not address this issue in their initial comments.

ALLIANCE: The Alliance did not address these Findings of Fact in its initial comments.

EMBARQ: Embarq did not address these Findings of Fact in its initial comments.

PUBLIC STAFF: The Public Staff stated that, although the CMRS Providers essentially agree with the Commission's decision to exclude the Mebane switch investment, they argue that MebTel's switching costs remain too high because they contain embedded costs. The Public Staff noted that the CMRS Providers contended that the Commission ignored the evidence presented by their witness Conwell in support of their position. The Public Staff also noted that, based on his testimony, the CMRS Providers contended that the Commission erred by not considering the FCC's switch price data in its conclusion on MebTel's switch investment. The Public Staff asserted that the Commission did not find witness Conwell's testimony as persuasive as the RLECs' evidence on this issue.

The Public Staff maintained that, first, witness Conwell testified that he computed MebTel's forward-looking switching investment based upon data derived by the FCC in 1999 from the FCC's *USF Inputs Order*, subject to a 12 percent reduction based upon the decline of switching costs since 1999 as shown by the AUS Price Index. The Public Staff noted that witness Conwell's 12 percent reduction, however, relied upon testimony by a CMRS Providers witness in a proceeding in Tennessee that switching and installation costs had declined over the last five to ten years. The Public Staff opined that, since this was the main support the CMRS Providers gave for the 12 percent reduction, the Commission did not err in declining to adopt the position that MebTel's switching costs should be reduced as a result.

The Public Staff maintained that, second, the Commission did not err by not relying upon the FCC's *USF Inputs Order* in its decision because, as the Commission found, that Order did not apply to rural carriers. The Public Staff stated that the Commission acknowledged in the *RAO* that the *USF Inputs Order* used a small sample of information from rural carriers in its estimated switch costs; however, it found that the *USF Inputs Order* pertained to nonrural carriers. The Public Staff maintained that the Commission further noted that the *USF Inputs Order* was released in 1999, so it was reasonable for the Commission to conclude that the data contained therein was dated and would not reflect the functionalities mandated by the FCC since 1999. Finally, the Public Staff maintained that the Commission found it more persuasive that the RLECs compute their own switch investments for purposes of establishing reciprocal compensation rates at levels equal to or lower than AT&T and Verizon, as shown in Public Staff Conwell Cross Examination Exhibit No. 1; it is not error for the Commission to weigh such evidence in making its determination.

The Public Staff asserted that, furthermore, even accepting the CMRS Providers' argument that switching costs had declined based on the AUS Price Index, the underlying numbers of this index are not clear. The Public Staff maintained that, without some clear indication that this price index includes all of the components of a switch, information that is not contained in witness Conwell's testimony, the Commission cannot conclude this is incontrovertible evidence that MebTel's switching investment should be lowered from what the Commission approved in the *RAO*.

The Public Staff noted that the CMRS Providers also argued that the switching costs are not TELRIC-based, because they are based upon embedded costs, and this appears to be the real basis for their objections. The Public Staff argued that, however, in Docket No. P-100, Sub 159, the Commission modified the requirement that the RLECs' reciprocal compensation rates be based upon TELRIC cost studies. The Public Staff maintained that, instead of using TELRIC-based cost studies, the Commission adopted seven guidelines for the RLECs to follow in producing an alternate cost study. The Public Staff opined that, contrary to witness Conwell's assertion, the cost study guidelines that were proposed by the Public Staff and adopted by the Commission do not impose the same requirements upon the RLECs as a TELRIC cost study would; otherwise, there would be no need for modification of the requirement to use TELRIC cost studies under Section 251(f)(2).

The Public Staff maintained that the arguments raised by the CMRS Providers in their Objections are not new; they were raised in testimony during the hearing and addressed again in briefs and proposed orders prior to the issuance of the *RAO*. The Public Staff stated that a review of the *RAO* shows that the Commission considered and rejected these arguments. The Public Staff asserted that, therefore, the CMRS Providers have provided no new reason for the Commission to reconsider Finding of Fact No. 8.

The Public Staff further noted that, in MebTel's Objections to Finding of Fact No. 10, it questions the Commission's use of $458 as the per line investment for switching. The Public Staff stated that the *RAO* has adopted the switching investment for MebTel that was included in Skrivan Rebuttal Exhibit No. 1; the amounts included in the *RAO* - $2,951,485 for the Mebane DCO switch and $3,931,474 for the Milton/Gatewood switches – only include the direct switch investment. The Public Staff noted that the Commission attributed an additional amount of $2,439,512 to the Mebane DMS switch. The Public Staff asserted that none of these amounts include investments associated with packet switching.

The Public Staff noted that, in addition, the investment amounts do not include $1,128,594 representing the common investments and the associated land and general support investments necessary for housing the switch. The Public Staff maintained that, as it noted in its Proposed Order, these investments are necessary for the overall functioning of the switch; thus, a portion of this amount should be allocated to the traffic-sensitive portion of the switching investment. The Public Staff asserted that this allocation is appropriate whether the Commission is considering a TELRIC study or a non-TELRIC study.

The Public Staff maintained that, since the Mebane DMS switch reflects 26.17 percent of MebTel's total switch investment, the Public Staff believes that the land, general support, and other common investment associated with the Mebane DCO and the Milton/Gatewood switches is $833,263 ($1,128,594 x [1 – 26.17 percent]). The Public Staff noted that, as a result, the Commission's calculations should include an additional $55 ($833,263 / 15,023 lines) investment per line to ensure that the costs for the support investments associated with MebTel's switches can be recovered through the reciprocal compensation rates. The Public Staff asserted that, as noted by MebTel in its Objections, this is consistent with the determination of these rates by the Commission in previous dockets determining the appropriate TELRIC-based UNE rates. The Public Staff provided the following Table to show the derivation of these amounts:

Switch	Direct	Percentage	Land and General
With Mebane DMS Switch			
Mebane DCO Switch	$2,951,485	31.66%	$357,312
Mebane DMS Switch	$2,439,512	26.17%	$295,331

Total Mebane Switches	**$5,390,997**	**57.83%**	**$652,643**
Milton/Gatewood Switches	**$3,931,474**	**42.17%**	**$475,951**
Total Switch Investment	**$9,322,471**	**100.00%**	**$1,128,594**
Number of Access Lines	15,023		15,023
Investment per Access Line	**$621**		**$75**
<u>Without Mebane DMS Switch</u>			
Mebane DCO Switch	$2,951,485		$357,312
Mebane DMS Switch	--		--
Total Mebane Switches	**$2,951,485**		**$357,312**
Milton/Gatewood Switches	**$3,931,474**		**$475,951**
Total Switch Investment	**$6,882,959**		**$833,263**
Number of Access Lines	15,023		15,023
Investment per Access Line	**$458**		**$55**

The Public Staff asserted that, in summary, the CMRS Providers have given the Commission no reason to amend its conclusion that the total switch investment per line of $458 is appropriate for use by MebTel in its calculations of traffic sensitive investment. The Public Staff noted that, further, the Commission should include an additional $55 per access line in investment for land and general support in its calculations when determining the appropriate level of traffic-sensitive costs for recovery through the transport and termination rates.

REPLY COMMENTS

RLECs: The RLECs did not specifically address this issue in their reply comments.

CMRS PROVIDERS: The CMRS Providers noted that the *RAO* concluded that the FCC switch cost data pertains to nonrural carriers, which will necessarily have different switching costs from rural carriers such as MebTel. The CMRS Providers stated that the RLECs claim in their initial comments that this conclusion is not arbitrary and capricious. The CMRS Providers asserted that they, however, do not argue that the Commission failed to consider the FCC switch cost data. The CMRS Providers noted that the Commission clearly examined the data. The CMRS Providers maintained that the Commission failed to consider, or simply overlooked, the fact that the data did include many rural carriers. The CMRS Providers noted Paragraph 299 of the FCC's *USF Inputs Order*, which states:

> The RUS sample contains 139 observations which provide information from across the nation on the costs of small switches purchased and installed by rural

> carriers. Over 80 percent of the observations of switch costs in the RUS data set measure the costs for switches with 1,000 lines of capacity or less.

The CMRS Providers asserted that, in light of this uncontroverted evidence, it was arbitrary and capricious for the *RAO* to find that the FCC switch cost data pertains to non-rural carriers.

The CMRS Providers also addressed the evidence they presented in the record (See witness Conwell's direct testimony at page 27) that switch prices have declined significantly over the past 15 to 20 years. The CMRS Providers stated that, in ruling that both Randolph and MebTel may base their transport and termination rates on embedded costs, the *RAO* ignored the evidence of switch price declines. The CMRS Providers noted that the RLECs asserted in their initial comments that the Commission could have rejected this evidence for any number of reasons. The CMRS Providers maintained, however, that none of the potential arguments are in the *RAO*, which simply ignores the record evidence on this point. The CMRS Providers stated that the RLECs tacitly admit the problem by arguing that state law presumes that the Commission considered and rejected the evidence of switch price declines, even though the *RAO* is silent on the point. The CMRS Providers argued that this state law standard, however, is not applicable under the federal law that must be applied to these proceedings. The CMRS Providers asserted that, under federal law, an agency is not presumed to have considered evidence not discussed in an order. The CMRS Providers stated that a state commission may not:

> [f]ind substantial evidence merely on the basis of evidence which in and of itself justifies [the commission's decision], without taking into account contradictory evidence or evidence from which conflicting inferences could be drawn.[1]

ALLIANCE: The Alliance did not file reply comments.

EMBARQ: Embarq did not address this issue in its reply comments.

PUBLIC STAFF: The Public Staff did not file reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth did not address this issue in their reply comments.

VERIZON WIRELESS: Verizon Wireless did not address this issue in its reply comments.

DISCUSSION

First, as a general matter, the Commission notes that it found in its *Modification Order* the following:

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[1] *Morall v. DEA*, 412 F.3d 165, 177 (D.C. Cir. 2005). See also *El Rio Cruz v. DHS*, 396 F.3d 1265, 1278 (D.C. Cir. 2005) (finding agency action arbitrary and capricious in failing to address relevant evidence before it); *Robinson v. NTSB*, 28 F.3d 210, 216 (D.C. Cir. 1994) (agency may not ignore testimony bearing on critical fact in case); *Lakeland Bus Lines v. NLRB*, 347 F.3d 955, 962 (D.C. Cir. 2003) (court cannot find substantial evidence solely on the basis of evidence that supports the result, without considering contradictory evidence.)

- that the RLECs are <u>not</u> required to perform TELRIC studies to establish reciprocal compensation rates; and
- that the RLECs should conduct alternative cost studies utilizing the seven guidelines recommended by the Public Staff.

No party sought reconsideration from the Commission's decision concerning these issues. Therefore, the Commission agrees with the RLECs that the unavoidable practical result of the *Modification Order* is that the RLECs are excused from having their reciprocal compensation rates determined based on TELRIC. The RLECs were instructed to file alternative cost studies not based on TELRIC, but based on the seven guidelines outlined in the *Modification Order*. Therefore, any discussion of whether the RLECs' alternative cost studies comply with TELRIC is beside the point.

The Commission notes that the CMRS Providers' first objection to Finding of Fact No. 8 is that it allows MebTel to reflect historical, booked switching investment rather than the current cost to purchase and install new switches. The Commission notes that the CMRS Providers' argument in this regard is not new and that the CMRS Providers asserted this contention numerous times as reflected in the record of evidence in this proceeding[1]. In fact, the Commission specifically notes on page 45 of the *RAO*:

> In this proceeding, MebTel has proposed using its historical, book cost of its switch investment as outlined above to produce a proposed $458 per line switch investment figure.

The Commission goes on in its discussion on page 46 of the *RAO* to state:

> The Commission also concludes that, generally, when company-specific information is readily available, it is better practice to use such information.

Further, although the Commission did not make this statement in its discussion of Finding of Fact No. 8 in the *RAO*, the Commission stated as follows in its discussion of Finding of Fact No. 12 on pages 67 through 68 (Question considered: Did Randolph's study use embedded costs, and if so, was that appropriate?):

> Guideline No. 2 of the Commission's *Modification Order* specified that, 'the cost data may be a surrogate of the company's cost, but should be forward-looking and reflect an efficient network to the extent practicable.' The Commission determines that this Guideline does not prohibit the use of any embedded costs in alternative cost studies...

As a result, the Commission has previously concluded that the fact that the RLECs' costs studies involve the use of embedded costs does not make them inconsistent with the Guidelines or applicable federal law.

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[1] The CMRS Providers' assertions that MebTel's proposed switching investment reflects historical, book costs are outlined on pages 42 through 44 of the *RAO*.

The CMRS Providers stated in their Objections that there are at least two simple and practicable ways the Commission can make MebTel's switching costs forward-looking: (1) modify MebTel's embedded switching investment to take into account the drop in switch prices over time; or (2) base MebTel's switching costs on the FCC's switch price data as reflected in the *USF Inputs Order*, also reduced for the decline in switch prices. The Commission notes that the CMRS Providers proposed these "solutions" in the record, the Commission acknowledged that these proposals had been made in its *RAO*, and the Commission rejected the proposals and decided, instead, to adopt MebTel's switch cost.

The Commission, in reaching its decision on Finding of Fact No. 8, considered and rejected witness Conwell's suggestion that switch prices have dropped 12 percent from 1999 to the present. The Commission noted his proposal several times in the *RAO*, specifically on pages 41, 43, 44, and 45. The Commission notes that the only evidence presented by the CMRS Providers to support this 12 percent reduction in switch costs is found on page 26, lines 4 through 10, of witness Conwell's direct testimony, where he testified as follows:

> Q. Are forward-looking switch investments lower than embedded switch investments?
>
> A. Yes, it is generally recognized in the telephone industry that the costs of switching systems have declined over time. In a similar arbitration of transport and termination rates in Tennessee, the cost expert for Sprint PCS indicated that costs to reproduce switches have declined by 12 and 31 percent over the past five and ten years, respectively.
>
> **Footnote 21** – The 12 and 31 percent declines in switch reproduction costs are based on the C.A. Turner Telephone Plant Index and information produced by Talmage O. Cox, III, a witness for Sprint PCS, in a similar arbitration in Tennessee (Supplemental Consolidated Direct and Rebuttal Testimony of Talmage O. Cox, III, Consolidated Docket 03-00585, Tennessee Regulatory Authority, 07/27/04, p. 11). Mr. Talmadge (sic) testified as follows:
>
> Q. Are the TPI index values for digital switching declining?
>
> A. Yes. The index factors for digital switching for the past five years have declined by 12 percent. Over the past ten years they have declined 31 percent. This confirms that the forward looking economic cost of switching would be less than the embedded cost of switching . . .

The Commission did not find the evidence of a 12 percent decline in switch costs persuasive and rejected the proposal. The Commission notes that the few sentences written to support such a reduction simply referenced the testimony of a Sprint PCS witness in a Tennessee arbitration proceeding. The Commission did not and still does not find this evidence convincing or persuasive so as to be adopted and applied to MebTel's switch costs in this proceeding.

The Commission, in reaching its decision on Finding of Fact No. 8, considered and rejected witness Conwell's suggestion that MebTel's switch prices should be based on the FCC's 1999 *USF Inputs Order*. The Commission noted his proposal several times in the *RAO*, specifically on pages 40 through 46. The Commission even specifically stated, in a separate, stand-alone paragraph, on page 46 of the *RAO*, that:

> The Commission also concludes that, generally, when company-specific information is readily available, it is better practice to use such information.

The Commission did not and still does not find witness Conwell's proposal to use data from the FCC's *USF Inputs Order* in lieu of MebTel's actual, historical switch costs persuasive. The Commission believes that use of MebTel's switch investment, modified to reflect the changes directed in the *RAO*, is consistent with the *Modification Order* and reasonable for use in MebTel's alternative cost study.

The Commission finds further support for its decision to adopt MebTel's company-specific, historical, book switch costs instead of witness Conwell's proposed switch cost based on the FCC's *USF Inputs Order* reduced by 12 percent by reviewing the words of the FCC itself in Paragraph 32 of the *USF Inputs Order*, as follows:

> For universal service purposes, we find that using nationwide averages is appropriate. The Commission has not considered what type of input values, company-specific or nationwide, nor what specific input values, would be appropriate for any other purposes. The federal cost model was developed for the purpose of determining federal universal service support, and it may not be appropriate to use nationwide values for other purposes, such as determining prices for unbundled network elements. We caution parties from making any claims in other proceedings based upon the input values we adopt in this Order.

As an additional matter, the Commission notes that the record developed on this issue focused mainly on the switching investment. MebTel noted that its cost study showed a total COE investment of $10,451,065, which consisted of $9,322,471 in direct investment in three switches plus another $1.1 million investment in land, buildings, and other equipment necessary to support operations of these switches. The RLECs and the Public Staff now note in their Objections and comments that the Commission failed to include investment for land and buildings in its determination of total investment. The Commission notes that witness Conwell's direct testimony stated that MebTel's cost study reflected land and building investment. However, he noted that switching made up the vast majority of plant and, therefore, focused his testimony on MebTel's switch investment figure of $9,322,471. Because the discussions in testimony focused solely on the switch investment and not on total investment, the Commission reached a decision on the appropriate switch investment without discussing or ruling specifically on the land and building investment. The Parties have discussed this issue in their Objections and comments to Finding of Fact No. 8 in addition to Finding of Fact No. 10. The Commission will address this issue here.

The Commission notes that witness Conwell, in his testimony, only contested the switching investment amount of $9,322,471 reflected by MebTel in its cost study. No party submitted evidence that the $1.1 million in land and building investment should not be included in MebTel's cost study, other than the CMRS Providers' overall proposal to simply adopt the switching investment of $143 per line proposed by witness Conwell. The Commission agrees with the Public Staff's calculation for the additional amount of investment for land and building that should be added to MebTel's switch investment to derive the total investment, as follows:

Line No.	Description	Amount
1.	Direct cost of Milton/Gatewood switches	$3,931,474
2.	Direct cost of Mebane DCO switch	$2,951,485
3.	Land and Building for Milton/Gatewood/Mebane DCO switches ($1,128,594 less 26.17% for Mebane DMS share or $1,128,594 x 73.83%)	$833,263
4.	Total Investment (Line 1 + Line 2 + Line 3)	$7,716,200
5.	Number of Access Lines	15,023
6.	Total Investment per Access Line	$514

Therefore, based on the discussion above, the Commission finds it appropriate to deny the CMRS Providers' Objections to Finding of Fact No. 8 and to uphold and affirm its decision in the *RAO* to adopt MebTel's switching investment per line of $458. Further, in addition to the $458 per access line in switching investment, an additional $56 per line should be added for land and building investment, for a total of $514 per line.

CONCLUSIONS

The Commission finds it appropriate to deny the CMRS Providers' Objections to Finding of Fact No. 8 and to uphold and affirm its decision in the *RAO* to adopt MebTel's switching investment per line of $458. Further, in addition to the $458 per access line in switching investment, an additional $56 per line should be added for land and building investment, for a total of $514 per line.

<u>FINDING OF FACT NO. 10 (ISSUE NOS. 10 AND 11 – MATRIX ISSUE NOS. 20 AND 21)</u>:

<u>ISSUE NO. 10 – MATRIX ISSUE NO. 20</u>: Should MebTel's transport and termination rate recover its nonusage sensitive switching costs?

<u>ISSUE NO. 11 – MATRIX ISSUE NO. 21</u>: If not, what percentage of total switching annual costs per line (18 and 19) should be recovered by MebTel's transport and termination rate?

INITIAL COMMISSION DECISION

The Commission concluded that MebTel's transport and termination rate should not recover the nonusage sensitive switching costs. Further, the Commission concluded that 38 percent of total switching annual costs per line should be recovered through MebTel's transport and termination rate.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel objected to Finding of Fact No. 10 and stated that the Commission's conclusions are based on a misapprehension and/or misapplication of Cingular Skrivan Cross Examination Exhibit 14 and other record evidence, which has apparently been misconstrued as supporting a conclusion that only 38 percent of MebTel's switching investment is usage sensitive. MebTel argued that the evidence shows that over 54 percent of MebTel's investment in its DCO switch in Mebane is usage sensitive and that the Commission should revisit its conclusion on this point. MebTel asserted that, absent such an action by the Commission, the reciprocal compensation rate established for MebTel will be materially flawed and not based on the evidence.

MebTel stated that the Commission's finding as to MebTel's usage sensitive switch investment is erroneous and contrary to the record evidence. MebTel stated that the finding may have been based on the testimony of CMRS Providers witness Conwell that 58 percent of MebTel's switch investment was for line side equipment and 4 percent was for voicemail equipment. MebTel maintained that the Commission is inaccurate in this regard. MebTel asserted that the record does not readily disclose the means by which the CMRS Providers calculated these percentages. MebTel stated that, however, it appears that they may have relied on Cingular Skrivan Cross Examination Exhibit 14, which consists of two summary pages from MebTel's Continuing Property Records (CPRs) covering MebTel's Mebane COE that consists of the Mebane DMS, DCO, and packet switching investment. MebTel noted that this summary document does not contain any cost information relating to the MebTel switches serving the Milton and Gatewood exchanges. MebTel stated that the CMRS Providers argued in their Brief that Cingular Skrivan Cross Examination Exhibit 14 establishes that only 38 percent of MebTel's switch investment is traffic sensitive.

MebTel noted that the CMRS Providers' contention that 58 percent of MebTel's investment in the DCO switch is for line side ports and not usage sensitive appears to be based on the ratio of investment shown in Skrivan Cross Examination Exhibit 14 – specifically, the ratio of $1,512,502.56 in line port costs to the $2,616,637.06 investment in the DCO switch – which is 57.8 percent. MebTel argued that this approach does not accurately reflect the extent of MebTel's usage sensitive investment in the Mebane DCO switch.

MebTel asserted that its cost study showed a total COE investment of $10,451,065 that consists of the $9,322,471 direct investment in three switches (the Mebane DCO, the Mebane DMS, and the switches serving Milton and Gatewood), plus another $1.1 million investment in land, buildings, and other equipment necessary to support operations of these switches[1]. MebTel noted that the direct investment included in that cost study for each switch is shown on Skrivan Rebuttal Exhibit 1: $2,951,485 for the Mebane DCO; $2,439,512 for the Mebane DMS; and $3,931,474 for the switches serving Milton and Gatewood, all of which total $9,322,471. MebTel stated that its cost study did not include investment in loop plant or MebTel's $1,737,804.04 investment in packet switching.

[1] See Skrivan Rebuttal Exhibit 3, Part 69-Form 1.

MebTel alleged that the CMRS Providers' approach to estimating MebTel's usage sensitive switch costs is driven by a desire to understate and minimize those costs. MebTel asserted that, for example, in Exhibit WCC-3, CMRS Providers witness Conwell showed line side port costs for the Mebane switches totaling $1,609,590 ($1,512,502.56 + $97,087.44). MebTel noted that, of this total amount, witness Conwell allocated line side port costs of $1,483,249 to the Mebane DCO switch and $0.00 to the Mebane DMS switch. MebTel stated that the Commission agreed that MebTel's investment in the Mebane DCO switch is $2,951,485. MebTel argued that, if $1,483,249 of that total investment did relate to line side port costs, then that amount would be 50 percent of MebTel's investment in that switch – not 58 percent as claimed by the CMRS Providers.

MebTel noted that Exhibit WCC-3 also shows that 3 percent of MebTel's investment in the DCO switch is for voicemail equipment – not 4 percent as testified to by witness Conwell. MebTel stated that, in Exhibit WCC-3, witness Conwell shows MebTel's power equipment investment as $309,676. MebTel maintained that witness Conwell allocates only $93,359 of that investment to the Mebane DCO switch and treated none of that investment as usage sensitive. MebTel asserted that, assuming the amount of that allocation is correct, witness Conwell noted that this was 4 percent of MebTel's investment in the Mebane DCO. However, he ignored that investment, even though a modern digital switch will not operate without electric power, and included no part of it in asserting that 22 percent of MebTel's Mebane switch investment is usage sensitive. MebTel noted that the power supply investment is a legitimate part of the getting started cost of a switch and that an appropriate portion of this investment should be included in determining the amount of usage-sensitive switch investment.

MebTel argued that inclusion of an appropriate portion of MebTel's investment to supply power to the Mebane DCO switch is fully consistent with the Commission's *Order Adopting Permanent Unbundled Network Element [UNE] Rates for BellSouth* issued December 30, 2003, in Docket No. P-100, Sub 133d (the *BellSouth UNE Order*). MebTel noted that, in that docket, which was a proceeding governed by the FCC's TELRIC rules, AT&T/WorldCom challenged BellSouth's calculation of its switching investment for purposes of establishing UNE prices. MebTel maintained that the *BellSouth UNE Order* is the basis for the Public Staff's position in the present dockets to the effect that the usage sensitive getting started cost of a switch consists of the entire cost of the switch, less the line port investment. MebTel argued that, if a consistent approach is followed here, then at least 50 percent of MebTel's investment in the DCO is usage sensitive ($1,483,249 / $2,951,485 = 50 percent).

MebTel stated that, in the BellSouth UNE proceeding, BellSouth defined "getting started costs" as follows: "The getting started investment is an investment which represents equipment items required to establish a new DMS (Nortel) or 5ESS (Lucent) office." MebTel noted that, under this definition, which the Commission accepted, MebTel's getting started costs for the Mebane DCO switch would also include investments in things such as land, buildings, and other equipment necessary to support the Mebane DCO switch. MebTel maintained that, as a practical matter, it is not possible to install a switch or operate it without land and a building to house the switch, or the other basic equipment necessary to establish and operate the Mebane DCO office.

MebTel noted that its cost study included $949,050 of investment for land and general support, which includes buildings and other equipment necessary to support and operate the switch. MebTel stated that its cost study included a total COE investment of $10,451,065, consisting of the $9,322,471 investment in three switches. MebTel asserted that, if a proportional percentage of the $949,050 land and support investment is allocated to the Mebane DCO ($2,951,485 / $9,322,471 = 31.66 percent), that adds $300,469 in land and support investment to MebTel's direct investment in the Mebane DCO of $2,951,485, and reveals that the true getting started investment in that switch is $3,251,954. MebTel argued that if, as shown in Conwell Exhibit WCC-3, the line port investment in the DCO is $1,483,249, then at least 54 percent of MebTel's investment in the Mebane DCO is usage sensitive[1].

MebTel asserted that, in the BellSouth UNE docket, the specific issue on switch cost was whether BellSouth had appropriately assigned switch investment outputs from its cost model for the getting started investment and the equivalent Plain Old Telephone Service (POTs) half calls investment to the minutes of use and feature elements. MebTel noted that the Commission approved BellSouth's allocation of the getting started and Equivalent POTs half calls (EPHC) investment, which are the costs for common equipment in the switch module. MebTel stated that, consistent with the *BellSouth UNE Order*, an adjustment recognizing that investments in power equipment, land, and support equipment are necessary to operate the Mebane DCO would further increase MebTel's usage sensitive investment in that switch.

MebTel noted that the getting started and EPHC investments, which terms the Commission used in the *BellSouth UNE Order*, were defined in the testimony of BellSouth witness Shell as follows:

> The getting started investment is an investment which represents equipment items required to establish a new DMS (Nortel) or 5ESS (Lucent) office. The switching module (SM) investment per EPHC represents the unit investment of SM equipment based on the realtime capacity of the SM processor.

MebTel stated that, given the breadth of the definition of getting started investment and the findings in the *BellSouth UNE Order*, it appears that the Commission concluded that all switch investment except line ports are usage sensitive. MebTel asserted that, applying the logic of the Commission's decision in the BellSouth UNE docket here, it is apparent that any usage sensitive factor less than 54 percent would understate MebTel's investment in the Mebane DCO switch.

MebTel noted that, finally, the Commission's proposed finding that only 38 percent of the MebTel DCO switch is usage sensitive is also contrary to the findings on this issue recommended by both MebTel and the Public Staff, and, if not corrected, will cause MebTel to dramatically under-recover its actual costs of providing the switching functionality used to terminate CMRS-originated traffic.

MebTel asserted that the Commission should either: (1) revise its finding on this point to accurately reflect that the percentage of MebTel's per line switch cost which is usage sensitive is 54 percent or (2) order MebTel and the CMRS Providers to conduct a joint review of MebTel's

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[1] Calculated as follows: (1 – ($1,483,249 / $3,251,954)) = 54 percent.

CPRs of the type the Commission directed with regard to Randolph's CPRs. MebTel noted that, through the joint review process, the parties can ensure that MebTel's cost data is being correctly interpreted by the CMRS Providers and the Commission can ensure that a materially flawed reciprocal compensation rate is not established for MebTel.

RANDOLPH: Randolph did not object to this Finding of Fact.

CMRS PROVIDERS: The CMRS Providers did not object to this Finding of Fact.

NON-PARTY COMMENTS

EMBARQ: Embarq did not comment on this Finding of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not comment on this Finding of Fact.

VERIZON WIRELESS: Verizon Wireless did not comment on this Finding of Fact.

INITIAL COMMENTS

RLECs: Since MebTel filed the initial Objection on this issue, the RLECs did not address this issue in their initial comments.

CMRS PROVIDERS: The CMRS Providers asserted that MebTel, in its Objections, argued that the Commission should either arbitrarily establish MebTel's usage-sensitive switching percentage at 54 percent or require the parties to conduct a joint review of MebTel's CPRs, as was done in the case of Randolph. The CMRS Providers noted that MebTel, in support of this claim, stated that costs for power equipment, land, buildings, and general support should be considered usage-sensitive. The CMRS Providers argued that including these costs in the development of a transport and termination rate ignores the FCC's definition of usage-sensitive, which requires that costs vary in proportion to the number of calls terminated. The CMRS Providers asserted that, clearly, the cost of land, buildings, and power equipment remains the same regardless of the number of calls processed.

The CMRS Providers noted that MebTel claimed that finding 38 percent of its switching costs to be usage sensitive will cause MebTel to dramatically under-recover its actual costs of providing the switching functionality used to terminate CMRS originated traffic. The CMRS Providers maintained that this statement confuses the nature of transport and termination rates, which may recover only the additional costs of terminating traffic. The CMRS Providers asserted that building costs are not additional costs, and neither are the costs of power equipment. The CMRS Providers stated that trunk costs, involving connections between switches, are usage-sensitive, because the more traffic that is switched, the greater trunk capacity that is needed; the same is not true for the other costs mentioned by MebTel.

The CMRS Providers maintained that MebTel is certainly entitled to recover its non-usage sensitive switching costs, but not through transport and termination rates charged to

CMRS Providers. The CMRS Providers stated that the Commission's initial decision was correct; MebTel's own CPRs demonstrate that 38 percent of MebTel's switching investment and costs are usage-sensitive.

ALLIANCE: The Alliance did not address this Finding of Fact in its initial comments.

EMBARQ: Embarq did not address this Finding of Fact in its initial comments.

PUBLIC STAFF: The Public Staff stated that this matter concerns whether the *RAO* has misstated the amount of traffic-sensitive investment that should be associated with MebTel's cost study. The Public Staff maintained that it has reviewed the *RAO*, as well as MebTel's Objection, and believes the *RAO* does not reflect all of the investment associated with MebTel's traffic-sensitive switch investment due to: (1) the overall investment amount to be included[1] and (2) the percentage of that investment to be designated as traffic-sensitive for purposes of the cost study. The Public Staff stated that it discussed the amount of switch investment used by the Commission in its initial comments on the Objections to Finding of Fact No. 8 and provided a recommendation in that discussion.

The Public Staff noted that the other issue concerns the Commission's use of percentages for trunking costs and getting started or switch matrix costs developed by CMRS Providers witness Conwell. The Public Staff maintained that, although the Commission adopted a Mebane DCO switch investment amount of $2,951,485, the amount reflected by witness Conwell in his Exhibit WCC-3 was only $2,616,637.

The Public Staff asserted that, as a result of witness Conwell using the lower total switch investment amount when calculating the percentage of line side port investment, the percentage is mathematically higher than would have been the case had he used the investment amount of $2,951,485 that the Commission found reasonable in Finding of Fact No. 8. The Public Staff maintained that both MebTel and the CMRS Providers accepted $1,483,249 as the correct line side port investment for the Mebane DCO. The Public Staff noted that, as a result of using the line side port investment percentage calculated by the CMRS Providers, the Commission has understated the percentage of switch investment to be assigned to the traffic-sensitive component of the Mebane DCO switch. The Public Staff argued that this percentage should be at least 49.75 percent (1 – [$1,483,249 / $2,951,485]). The Public Staff stated that, when calculating the total traffic sensitive investment, an equivalent percentage of the land and support investments addressed above should also be calculated as well.

The Public Staff maintained that the Commission should consider 70 percent of the costs relating to the Milton/Gatewood switches as being the traffic-sensitive component. The Public Staff argued that, in adopting a different percentage, the Commission noted the lack of evidence in the record as to the size of the rural carriers to which the FCC's 70 percent figure was applied. The Public Staff asserted that it is not logical for the FCC to use a definition of a rural carrier that is inconsistent with that specified in the Act. The Public Staff noted that, thus, it believes the FCC used the term "rural carrier" as it is defined pursuant to the Act; for that reason, "rural carriers" may be any size, so long as they are classified as "rural carriers" pursuant to the Act.

[1] The Commission addresses this issue in its discussion on Objections to Finding of Fact No. 8.

The Public Staff opined that, as such, the FCC's 70 percent figure would apply to carriers both larger and smaller than the three rural carriers in this proceeding. The Public Staff maintained that, therefore, the Commission's concern about the lack of evidence on the size of the rural carriers to which the FCC's figure was applied is misplaced.

The Public Staff noted that the amount of MebTel investment to treat as traffic-sensitive can be determined by taking the total investment amounts shown in Table 1 of the Public Staff's initial comments regarding the Objection to Finding of Fact No. 8 and then applying the appropriate traffic-sensitive factor. The Public Staff stated that the following table, identified as Table 2 in the Public Staff's initial comments, shows the calculation:

	Mebane DCO	Milton/Gatewood	Total
Direct	$2,951,485	$3,931,474	$6,882,959
Land and General	$357,312	$475,951	$833,263
Total	**$3,308,797**	**$4,407,425**	**$7,716,222**
Traffic-Sensitive Factor	49.75%	70.00%	
Traffic-Sensitive Investment	**$1,646,126**	**$3,085,197**	**$4,731,324**

The Public Staff recommended that the Commission revise Finding of Fact No. 10 to reflect a traffic-sensitive factor of 49.75 percent for the Mebane DCO and 70 percent for the Milton/Gatewood switches. The Public Staff noted that this would produce a traffic-sensitive investment of $4,731,324, or $315 per access line.

REPLY COMMENTS

RLECs: The RLECs noted in their reply comments that the CMRS Providers oppose MebTel's Objection to the *RAO* finding that 38 percent of MebTel's switch investment is usage-sensitive. The RLECs stated that, by its Objection, MebTel pointed the Commission to record evidence establishing that MebTel's usage-sensitive switch investment is slightly over 54 percent. The RLECs asserted that, based on that evidence, MebTel requested that the Commission either revise its finding as to the extent of MebTel's usage-sensitive switch investment or, alternatively, that the Commission direct the parties to conduct a joint review of MebTel's CPRs – as has been done for Randolph.

The RLECs stated that the CMRS Providers first depict MebTel as requesting that the Commission arbitrarily establish MebTel's usage-sensitive switching investment at 54 percent. The RLECs argued that, as shown by both MebTel's Objection and the Public Staff's comments, that statement is simply not true. The RLECs noted that, in its Objection, MebTel pointed to specific record evidence showing that a 38 percent usage-sensitive factor is too low and would be inconsistent with the greater weight of the evidence concerning the extent of MebTel's usage-sensitive switch investment. The RLECs asserted that there is nothing arbitrary about MebTel's request, which is based on record evidence cited in its Objection which establishes that 54.6 percent of MebTel's switch investment in the Mebane DCO switch is usage-sensitive.

The RLECs maintained that there is, likewise, nothing arbitrary about the Public Staff's conclusion in its initial comments that at least 49.75 percent of MebTel's investment in the Mebane DCO switch is usage-sensitive. The RLECs stated that the Public Staff, in its initial comments, supports MebTel's Objection by pointing out other record evidence establishing that at least 49.75 percent of MebTel's investment in the Mebane DCO switch is usage-sensitive. The RLECs stated that the Public Staff noted the Commission's finding that MebTel's investment in the Mebane DCO switch is $2,951,485. The RLECs asserted that both MebTel and the CMRS Providers accepted $1,483,249 as the line side port investment in that switch. The RLECs stated that, as pointed out by the Public Staff, this means that the usage-sensitive portion of the Mebane DCO switch is at least 49.75 percent ($1,483,249 / $2,959,485). The RLECs argued that the approach for determining the usage-sensitive switch investment advocated by the Public Staff (that all switch investment except for line-side port costs is usage-sensitive) is the same approach that the Commission used in establishing TELRIC-based UNE rates for BellSouth, Embarq, and Verizon in Docket No. P-100, Sub 133d.

The RLECs stated that the Public Staff also recognized the validity of the fact noted in MebTel's Objection that the *RAO* does not reflect all of the investment associated with MebTel's traffic-sensitive switch investment. The RLECs asserted that the CMRS Providers not only want to ignore most of the RLECs' switch investment, they likewise seek to ignore the power equipment, building, land, and other support investments that are necessary for an RLEC to operate a switch. The RLECs stated that MebTel pointed out in its Objections that some portion of its investments in power equipment, land, buildings, and general support, all of which are essential for the operation of a switch, should be considered usage-sensitive, as they are the very type of getting started costs the Commission allowed BellSouth and others to recover through their usage-sensitive UNE rates. The RLECs argued that the practical reality is that it is not possible to install or operate a switch without land on which to place a building to house the switch, power to energize the switch, or the other basic equipment necessary to establish and operate the switch.

The RLECs noted that the Public Staff, based on its analysis of the record evidence concerning MebTel's switch investment, advocated that the Commission include an additional $55 per line ($833,263 in land and general support investment spread over MebTel's 15,023 lines) to insure that MebTel's support investments associated with its switches are recovered through reciprocal compensation. The RLECs stated that, when added to the $458 per line switch investment already recognized by the Commission, this yields a total investment per line of $513 for Mebtel.

The RLECs maintained that the CMRS Providers say that MebTel is entitled to recover these switch costs but not through transport and termination rates charged to CMRS Providers. The RLECs said that, instead, the CMRS Providers contended that these very real components of the cost of providing switching are not usage-sensitive because they do not vary in proportion to the number of calls terminated. The RLECs noted that, again, it is the CMRS Providers' position that 0 percent of the switch investment is usage-sensitive and that only trunking costs, consisting of the connection between switches, are usage-sensitive.

The RLECs asserted that the CMRS Providers' argument on this point is unsupportable for two reasons: first, it overlooks the practical reality of the investments an RLEC must make in order to provide the switching functionality necessary to terminate a CMRS-originated call and, second, it is premised on the continuing efforts of the CMRS Providers to apply the FCC's TELRIC requirements and Section 252(d) in this proceeding, even though the Commission's *Modification Order* excused the RLECs from having to provide TELRIC-compliant cost studies or to have their reciprocal compensation determined based on the FCC's TELRIC rules.

The RLECs noted that, in addition to pointing out the evidence showing that at least 49.75 percent of the Mebane DCO switch investment is usage-sensitive, the Public Staff also renewed its argument that the Commission should find that 70 percent of MebTel's investment in its Milton/Gatewood switches is traffic-sensitive. The RLECs stated that MebTel agrees with the Public Staff on this point and likewise renews its request that the Commission so find. The RLECs noted that the CMRS Providers concede that MebTel is a rural telephone company under the Act. The RLECs also noted that, as the Public Staff pointed out, the FCC has indisputably recognized the appropriateness of rural carriers treating 70 percent of their switch investment as usage-sensitive.

The RLECs concluded that MebTel endorses the Public Staff's recommendation that the Commission revise Finding of Fact No. 10 to reflect usage-sensitive factors of at least 49.75 percent for the Mebane DCO switch and 70 percent for the Milton/Gatewood switches. The RLECs maintained that these adjustments, together with the addition of MebTel's land and general support investment of $55 per line, yields a total usage-sensitive switch investment of $4,731,324, which is $315 per access line.

CMRS PROVIDERS: The CMRS Providers noted that the Public Staff supports MebTel's claim that its transport and termination rate should include an additional $55 per access line for the costs of land, general support, and other common investments. The CMRS Providers maintained that the key question in MebTel's cost study is the portion of MebTel's switching investment that is traffic sensitive. The CMRS Providers alleged that the Public Staff claimed that MebTel's investment for land and general support should be included in MebTel's appropriate traffic sensitive costs – without inquiring whether such investment is actually traffic sensitive.

The CMRS Providers asserted that the Act allows MebTel's rate to recover the additional costs (See Section 252(d)(2)(A)(ii) of the Act) associated with the transport and termination of wireless traffic. The CMRS Providers maintained that the FCC has interpreted the additional cost standard as limiting recovery to traffic-sensitive costs (See Paragraph 1057 of the *First Report and Order*). The CMRS Providers stated that the FCC has given a clear definition of "traffic sensitive" by stating:

> [T]he 'additional cost' to the LEC of terminating a call that originates on a competing carrier's network primarily consists of the traffic-sensitive component of local switching. The network elements involved with the termination of traffic include the end-office switch and local loop. The costs of local loops and line ports associated with local switches do not vary in proportion to the number of

> calls terminated over these facilities. We conclude that such non-traffic sensitive costs should not be considered 'additional costs' when a LEC terminates a call that originated on the network of a competing carrier. (Paragraph 1057 of the FCC's *First Report and Order*)

The CMRS Providers argued that, clearly, the costs of land and general support do not vary with the number of wireless calls processed; such costs will remain the same whether MebTel terminates 1,000 or 100,000 minutes from wireless carriers. The CMRS Providers concluded that, under federal law, the Public Staff's suggestion in this regard must be rejected.

ALLIANCE: The Alliance did not file reply comments.

EMBARQ: Embarq did not address this issue in its reply comments.

PUBLIC STAFF: The Public Staff did not file reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth did not address this issue in their reply comments.

VERIZON WIRELESS: Verizon Wireless did not address this issue in its reply comments.

DISCUSSION

The Commission notes that MebTel originally took the position that 100 percent of its switching costs should be included in its alternative cost study and that 0 percent should be deducted as non-usage sensitive costs. Therefore, MebTel did not advocate that a specific percentage of its costs that be deemed usage sensitive in anticipation that the Commission would find that only usage sensitive switching costs should be included in the alternative cost study. Therefore, the Commission was left with the CMRS Providers' proposal that 38 percent of MebTel's switching costs are usage sensitive, a figure which was based on 16 percent for trunking equipment and 22 percent for the switch matrix. The CMRS Providers asserted that MebTel had not disputed those figures[1]. The Public Staff recommended a percentage of 43 percent as usage sensitive based on simply subtracting the line port investment associated with the Mebane DCO switch of 57 percent from 100 percent to arrive at a figure of 43 percent for usage sensitive costs. The Commission found it to be the better practice to use the known, actual percentages provided by the CMRS Providers to establish the usage sensitive switching costs instead of backing into a percentage as the Public Staff proposed (100 percent – 57 percent for line port investment = 43 percent).

MebTel has filed an Objection to the *RAO's* conclusion that 38 percent of MebTel's switching costs are usage sensitive and, instead, contends that the actual figure is 54 percent. MebTel did not object to the Commission's finding that only usage sensitive switching costs should be reflected in MebTel's alternative cost study, nor did MebTel object to the Commission's decision in the *RAO* that the same usage sensitive percentage determined for the Mebane DCO switch should be applied to the Milton and Gatewood switches.

[1] This assertion by the CMRS Providers was noted on page 53 of the *RAO*.

MebTel requests in its Objections that the Commission conclude that 54 percent of its switching costs are usage sensitive. MebTel arrived at its proposed figure, as follows:

Line No.	Description	Amount
1.	Investment in Mebane DCO	$3,251,953[1]
2.	Less Line Side Port Investment	$1,483,249[2]
3.	Total (Line 1 minus Line 2)	$1,768,704
4.	Percentage Usage Sensitive (Line 3 divided by Line 1)	54%

The Public Staff proposed that the Commission revise its decision concerning this issue so as to find that 49.75 percent of the Mebane DCO switch and 70 percent of the Milton and Gatewood switches are usage sensitive. The Public Staff derived its proposed percentage as follows:

Line No.	Description	Value
1.	One Minus	1
2.	Line Side Port Investment for Mebane DCO	$1,483,249
3.	Divided by Mebane DCO switch investment	$2,951,485
4.	Usage Sensitive Factor – Line 1 – (Line 2/ Line 3)	49.75%

MebTel supported the Public Staff's calculation of a 49.75 percent usage sensitive factor in its reply comments.

The Commission finds that it is appropriate to reconsider its decision on the appropriate usage sensitive switching costs for MebTel. The Commission finds the analysis provided by the RLECs and the Public Staff in their filings in this regard to be persuasive. As a result, the Commission finds it appropriate to take the switch investment of $2,951,485 adopted by the Commission in the *RAO* and divide it by the agreed-upon level of Line Side Port Investment for the Mebane DCO of $1,483,249 and subtract the result from 1 to derive a usage sensitive switching percentage of 49.75 percent.

The Commission notes that the CMRS Providers did not refute or challenge the calculation of the 49.75 percent figure. Nor did they provide additional support or explanation of the 38 percent figure they originally recommended and the Commission adopted in the *RAO*. Instead, the CMRS Providers focused their comments on the definition of usage sensitive and the additional cost standard outlined in Section 252(d)(2)(A)(ii) of the Act. However, the Commission notes that the reciprocal compensation rates established in this proceeding have not and should not be set based on Section 252(d)(2)(A)(ii) of the Act, but are and should be based on the seven guidelines outlined in the *Modification Order*.

As noted above, the reason the Commission originally adopted the 38 percent factor was because MebTel did not offer testimony on the appropriate factor and the CMRS Providers asserted that MebTel did not refute the numbers it used to make up the 38 percent. The Commission is convinced by the filings made after the issuance of the *RAO* that its original

[1] Equals $2,951,485 of COE investment (plant) and $300,468 in land and general support.

[2] MebTel, the CMRS Providers, and the Public Staff agree that the figure of line side ports is correct.

decision should be modified to reflect 49.75 percent as the usage sensitive switching factor to be included in MebTel's alternative cost study. As found in the Commission's discussions on Finding of Fact No. 8 in this Order, the 49.75 percent factor should be applied to a total investment figure of $7,716,200.

Finally, the Commission notes that no party filed a formal Objection in a timely manner concerning the Commission's decision in the *RAO* to apply the usage sensitive percentage determined for the Mebane DCO switch to the Milton and Gatewood switches. The Public Staff asserted in its initial comments that the Commission should revise this decision to use a 70 percent factor for the Milton and Gatewood switches, and MebTel supported the Public Staff's recommendation in this regard in its reply comments. However, the Commission does not believe that a formal objection has been made concerning this decision and is not altering the conclusion to apply the same usage sensitive percentage of the Mebane DCO switch to the Milton and Gatewood switches reached in the *RAO*.

CONCLUSIONS

The Commission concludes that it is appropriate to revise the usage sensitive factor to be applied in the MebTel cost study to 49.75 percent. This factor is to be applied to the total investment figure of $7,716,200, which reflects the switch investment in the Mebane DCO, Milton, and Gatewood switches and an appropriate portion for land and building investment.

<u>FINDING OF FACT NO. 11 (ISSUE NO. 12 – MATRIX ISSUE NO. 22)</u>: Did Randolph's cost study use appropriate cost data?

<u>FINDING OF FACT NO. 12 (ISSUE NO. 13 – MATRIX ISSUE NO. 23)</u>: Did Randolph's study use embedded costs, and if so, was that appropriate?

<u>FINDING OF FACT NO. 28 (ISSUE NO. 30 – MATRIX ISSUE NO. 31)</u>: Does Randolph's alternative cost study based on interstate average schedule costs comply with the alternative cost study Guidelines established by the Commission in Docket No. P-100, Sub 159?

INITIAL COMMISSION DECISIONS

<u>FINDING OF FACT NO. 11</u>: The Commission concluded that Randolph's alternative cost study used appropriate cost data and should be adopted. However, Randolph should update its alternative cost study to reflect the NECA average schedule formulae adopted for the one-year period beginning on July 1, 2007 and the most current Local Switching Support (LSS) formulas.

<u>FINDING OF FACT NO. 12</u>: The Commission concluded that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units; however, Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*.

FINDING OF FACT NO. 28: The Commission concluded that once the adjustments ordered in the *RAO* are made, Randolph's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel did not object to these Findings of Fact.

RANDOLPH: Randolph stated that it does not object to these proposed findings; instead, it objects to the Commission not having explicitly provided for Randolph, in updating its cost study, to also update the number of lines and projected usage in re-calculating its costs in the updated cost study called for by the *RAO*.

Randolph stated that it believes that it would be both appropriate and logical, if Randolph is to update its cost study to incorporate the latest NECA formulae, for the updated study to also include the most current information on Randolph's access lines and projected usage.

Randolph noted that its original cost study involved use of a projection of its access lines and access usage based on a twelve-month average of these data for the period ending July 2006, with the projections including a percentage growth rate for that period from the previous twelve-month period[1]. Randolph maintained that, during the course of reviewing Randolph's CPRs with the CMRS Providers, as directed in Finding of Fact No. 17 of the *RAO*, Randolph provided data to the CMRS Providers showing the impact on Randolph's costs resulting from use of the most current NECA average schedule formulae. Randolph stated that it also provided updated information as to its access line and interstate access usage through December 2007 and its projected lines and usage again based on growth for the twelve-month period ending December 2007 in comparison to the previous twelve months.

Randolph noted that it does not yet know if the CMRS Providers object to Randolph updating its cost study to include the most current data available on access lines and projected usage. However, Randolph asserted that it believes that it is necessary and appropriate that, having been directed to update its cost study to utilize the latest NECA formulae, it should also update its study to reflect the most current data on lines and usage. Randolph stated that those inputs, like the underlying NECA formulae, play an important role in Randolph's alternative cost study, and Randolph submits that, if its study is to be updated, then it should be updated to include the most current information. Randolph requested that the Commission amend Finding of Fact No. 11 to include language allowing Randolph to so update its alternative cost study.

CMRS PROVIDERS: The CMRS Providers objected to these Findings of Fact and stated that Randolph's original transport and termination cost study filed with the direct testimony of witness Schoonmaker produced an estimated cost of $0.0217 per minute. The CMRS Providers noted that this cost study result and the underlying cost components are shown in the table below (first column).

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[1] See Exhibit RCS-3 of witness Schoonmaker's testimony.

Randolph Transport and Termination Costs				
	Original Schoonmaker Direct	Corrected Schoonmaker Rebuttal	Randolph Revised per *RAO*	MebTel Revised per *RAO*
Switching (termination)	$ 0.0100	$ 0.0100	$ 0.0042	$ 0.0036
Transport	$ 0.0099	$ 0.0073	$ 0.0075	$ 0.0016
Signaling	$0.0018	$0.0018	$0.0021	N/A
Total	$ 0.0217	$ 0.0192	$ 0.0138	$ 0.0052

The CMRS Providers stated that the original cost study, based on NECA average schedule formulae, suffered from a number of flaws that caused its results to conflict with the *Modification Order's* Guidelines for cost studies. The CMRS Providers maintained that, specifically, the study reflected embedded plant investment and costs, did not adequately reflect Randolph's own costs, and inappropriately included loop costs.

The CMRS Providers contended that Randolph recognized its error in including loop costs and revised its cost study. The CMRS Providers stated that Randolph then filed new cost results with witness Schoonmaker's rebuttal testimony. The CMRS Providers stated that these new results are also shown in the table above (second column). The CMRS Providers asserted that Randolph's revised study continued to use the NECA average schedule formulae, thus continuing to reflect embedded plant investment and costs not adequately reflecting Randolph's own costs. The CMRS Providers noted that, nevertheless, correcting the loop cost error lowered the proposed rate from approximately $2.2 cents to $1.9 cents per minute.

The CMRS Providers argued that the *RAO's* ruling on Matrix Issue Nos. 22, 23, and 31 (*RAO* Issues 12, 13, and 30) accepted Randolph's revised cost study, subject to two conditions. The CMRS Providers noted that, first, the study was to be updated to reflect the current NECA average schedule and LSS formulae and second, a study of Randolph's CPRs was to be performed by the parties to determine Randolph's usage-sensitive percentage of switching costs.

The CMRS Providers argued that, in making this sweeping conclusion to accept Randolph's revised cost study, subject to these two conditions, the *RAO*, in effect, declined to address the specific issues raised by the CMRS Providers about Randolph's cost study and its compliance (or lack thereof) with the Guidelines in the *Modification Order*. The CMRS Providers asserted that this is a fundamental and reversible error in the *RAO*.

The CMRS Providers noted that Randolph and the CMRS Providers have now met and conferred concerning updating Randolph's revised study for current NECA and LSS formulae. The CMRS Providers noted that the parties have also analyzed Randolph's CPRs. The CMRS Providers stated that Randolph has determined that 52.6 percent, rather than 70 percent, of its switching costs are usage-sensitive. The CMRS Providers asserted that they disagree with this figure. The CMRS Providers noted that Randolph has again revised its cost study and now claims a transport and termination cost of $0.0138 per minute as shown in the table (third column).

The CMRS Providers stated that Randolph's transport and termination cost and proposed rate, by Randolph's own admission, have declined from approximately 2.2 cents to 1.4 cents per minute; a rate of 1.4 cents per minute, however, still does not comply with the Guidelines of the *Modification Order*.

The CMRS Providers argued that the *RAO* failed to recognize three essential facts and their combined effect on Randolph's switching costs (as well as transport and signaling costs), as follows:

1. The switching cost data reflected in the NECA formulae represent embedded plant investment and the costs associated with this investment – depreciation expense to recover the past, sunk investment, the cost of money on the sunk investment, income taxes and operating expenses. This fact is established in evidence.

2. The current cost to purchase and install new switches, or reproduction cost, has declined over time – and declined substantially (12 percent since 1999 based on the AUS Price Index). This fact is established in evidence and cannot be ignored.[1] Plainly put, it means that embedded switching cost data are not valid surrogates for forward-looking costs; and, no matter now "practicable" it is to use the NECA formulae to compute switching costs, the results do not comply with Guideline 2. As described below, it is exceedingly "practicable" to make at least some adjustment to the embedded switching costs in the Randolph cost study to put them more near a current cost basis.

3. In its Ruling on Matrix Issue No. 23 (Finding of Fact No. 12), the *RAO* approves Randolph's use of embedded cost data in its study, because, "[t]he Commission concludes that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units." It is misguided to think that combining embedded costs with forward-looking demand will produce appropriate transport and termination costs. Randolph's use of forward-looking demand units did not cause its cost estimate to be forward-looking; it instead exacerbated the original error. Randolph's minutes of use (and lines in service) are declining. Dividing past, sunk switching costs by declining demand simply raises switching costs per minute. Thus, by forecasting fewer minutes of use, Randolph achieves the perverse effect of raising its rate for termination. Indeed, in its latest update to its cost study (to

[1] Conwell Direct, p. 26: "[I]t is generally recognized in the telephone industry that the costs of switching systems have declined over time. In a similar arbitration of transport and termination rates in Tennessee, the cost expert for the Sprint PCS indicated that costs to reproduce switches have declined by 12 and 31 percent over the past five and ten years, respectively." *See also* Conwell Cross-Examination Exhibit 2 and the cross-examination on pages 272-275 of the Hearing Transcript, Vol. II.

> comply with the *RAO* and reflect current NECA and LSS formulae), Randolph has done just that. During discussions among the parties, Randolph has shared this latest update, which Randolph will file with the Commission. The projected monthly interstate minutes used to compute "per-minute" transport and termination costs have been lowered from 707,788 to 610,415 minutes. All other things being the same, this change in "forward-looking demand units" further raises Randolph's (embedded) cost estimate by 16 percent (16 percent = 707,708/610,415 – 1).

The CMRS Providers maintained that, without apparent critical evaluation of the evidence, the Commission has effectively given Randolph the latitude to ignore Guideline 2 in the *Modification Order*, such that Randolph is being allowed to recover embedded switching costs over an ever-declining demand figure. The CMRS Providers argued that this is completely contradictory to the competitive and economic principles inherent in the Act, FCC Rules, and *Modification Order* Guidelines.[1]

The CMRS Providers asserted that, furthermore, it is simply false to claim that Randolph had no "practicable" alternative to using embedded cost data and the NECA formulae. The CMRS Providers maintained that, to make its study forward-looking, Randolph's latest switching cost of $0.0042 per minute needs to be adjusted in two simple ways.

The CMRS Providers stated that, first, Randolph's switching cost should be reduced by the 12 percent decline in switch reproduction costs since 1999 (based on the AUS Price Index). The CMRS Providers noted that this lowers the embedded switching cost per minute from $0.0042 to $0.0037 per minute ($0.0037 = $0.0042 x (1 – 12 percent)).

The CMRS Providers noted that, second, this $0.0037 per minute switching cost can be adjusted to reflect a more efficient level of utilization of its switch, rather than the declining utilization forecast in the future. The CMRS Providers stated that one of the *Modification Order's* Guidelines is that "[t]he cost data . . . should reflect an efficient network to the extent practicable". The CMRS Providers stated that FCC rules also require that Randolph's cost study assume "the most efficient technology for reasonably foreseeable capacity requirements."[2] The FCC adopted this approach because it "encourages facilities-based competition to the extent that new entrants, by designing more efficient network configurations, are able to provide the service at a lower cost than the incumbent LEC."[3]

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[1] *First Report and Order*, Paragraph 705: "[W]e reiterate that the prices for the interconnection and network elements critical to the development of a competitive local exchange should be based on the pro-competition, forward-looking, economic costs of those elements, which may be higher or lower than historical embedded costs. Such pricing policies will ensure the efficient investment decisions and competitive entry contemplated by the 1996 Act, which should minimize the regulatory burdens and economic impact of our decisions on small entities."

[2] *First Report and Order*, Paragraph 685.

[3] *Id.*

The CMRS Providers noted that Randolph witness Schoonmaker's original Confidential Exhibit RCS-2 indicated that, from mid-2004 to mid-2005, Randolph's switching plant was handling 721,800 monthly interstate minutes or 18 percent more usage than is reflected in the latest cost study (18 percent = 721,800/610,415 – 1). The CMRS Providers stated that Guideline 2 requires cost data to reflect efficient network usage. The CMRS Providers maintained that, without knowing the absolute utilization level of Randolph's switching plant, it is clear that it was more efficiently utilized from mid-2004 to mid-2005 than it is today. The CMRS Providers contended that, to better comply with Guideline 2, the $0.0037 per-minute switching cost should be reduced to $0.0031. The CMRS Providers noted that this figure is still 35 percent greater than the forward-looking switching cost of $0.0023 per minutes computed for Randolph by witness Conwell. The CMRS Providers asserted that these two adjustments are practicable and supported by uncontroverted evidence in the record.

The CMRS Providers argued that, if the Commission does not require these two adjustments to Randolph's latest switching cost estimate, it will be perpetuating a rate-making philosophy that permits local exchange carriers to recover sunk costs over whatever demand exists, rather than setting rates based on the economic costs of providing service. The CMRS Providers contended that this ratemaking philosophy does not work in competitive markets and is prohibited by the Act and FCC Rules.

The CMRS Providers stated that, before concluding their Objections to the *RAO's* findings and conclusions with respect to Randolph's switching costs, the CMRS Providers would make two concluding comments on the "practicability" of obtaining forward-looking cost data. The CMRS Providers noted that this is important because Randolph, like the other RLECs, is using this "practicability loophole" as a means to recover embedded costs, which is contrary to the Act, FCC Rule 51.505(d)(1), and importantly Guideline 2 of the *Modification Order.*

The CMRS Providers maintained that the Commission's *Modification Order* required Randolph to use forward-looking cost data in its study "to the extent practicable." The CMRS Providers asserted that the record, however, demonstrates that Randolph determined, before its study was even commenced, to use embedded cost data and to make no effort at all to employ forward-looking data in its study.

The CMRS Providers noted that Schoonmaker Cross-Examination Exhibit 3 is a copy of a document that was prepared by witness Schoonmaker for Randolph to review in determining how to perform the cost study submitted to the Commission in this case. The CMRS Providers maintained that the document lists six alternative studies that witness Schoonmaker offered to perform for Randolph.[1] The CMRS Providers asserted that each alternative was briefly described, then was followed by the heading "Issues with Staff Guidelines." The CMRS Providers noted that, as confirmed at the hearing, Randolph chose the second alternative listed in the exhibit: "Interstate Settlement by Category."[2]

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[1] Hearing Transcript, Vol. II, page 110, lines 12 through 15 (testimony of witness Schoonmaker): "These were several different alternative possible cost study methods that we suggested might be considered if we were given the opportunity to work in this project."

[2] Hearing Transcript, Vol. II, page 113, lines 10 through 16.

The CMRS Providers maintained that, under the heading "Issues with Staff Guidelines," the alternative chosen by Randolph contains the following sentence: "There would be no forward-looking element to the costs."[1] The CMRS Providers noted that, in fact, the first three alternatives listed on the document all contain the same comment: "There would be no forward-looking element to the costs." The CMRS Providers asserted that the last three alternatives contain the following sentence: "There would be no forward-looking element to the costs if embedded costs were used."

The CMRS Providers contended that witness Schoonmaker, in short, notified Randolph before work on the cost study even began that the second alternative – the one chosen by Randolph – would not contain forward-looking costs and that this fact would raise an "Issue with Staff Guidelines."

The CMRS Providers argued that no evidence could be clearer that Randolph made no attempt at all to employ forward-looking cost data in its study. The CMRS Providers asserted that Randolph made a conscious decision, before work on the cost study was even started, not to use forward-looking data and that this decision constituted a direct violation of the Commission's *Modification Order*.

The CMRS Providers maintained that Randolph's switching cost, after the modifications required by the *RAO* (including the reduction of the percentage of usage-sensitive switching investment), is $0.0042 per minute, according to Randolph. The CMRS Providers argued that simple and "practicable" adjustments to the $0.0042 per minute switch cost value can be made by (1) using the AUS Price Index to reflect lower forward-looking investment and costs, (2) using mid-2004 to mid-2005 demand as "efficient usage" of Randolph's network, and (3) removing software upgrade investments from the usage-sensitive percentage of switching costs. The CMRS Providers contended that these three simple modifications, based on uncontroverted record evidence, are imminently "practicable" and will result in a switching cost for Randolph of no more than $0.0023 per minute (witness Conwell's estimate of forward-looking switching costs). The CMRS Providers maintained that, in other words, the Commission can make a proper decision based on the record evidence and the Guidelines in the *Modification Order*. The CMRS Providers asserted that failure to make these simple corrections, given the record in this case, would be arbitrary and capricious.

The CMRS Providers noted that Randolph's transport cost was not modified by the *RAO* and has remained at approximately $0.0075 per minute after its initial correction to remove loop costs. (See table above.) The CMRS Providers opined that, as with switching, the transport cost is based on the NECA average schedule formulae and therefore reflects embedded transport investment and costs and is not reflective of Randolph's own costs. The CMRS Providers maintained that the uncontroverted record evidence makes clear that a transport cost for Randolph of $0.0075 per minute is grossly inflated.

The CMRS Providers asserted that several items of uncontroverted evidence demonstrate this point:

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[1] Schoonmaker Cross-Examination Exhibit 3.

(i) Disparity Between witness Conwell's Estimate of Transmission Equipment Costs and the Value in Randolph's Study

The CMRS Providers noted that witness Conwell, in his summary at the evidentiary hearing, presented a forward-looking transport cost estimate for Randolph of $0.0022 per minute based on company-specific and publicly available cost data. The CMRS Providers asserted that witness Conwell's estimate is 29 percent of Randolph's cost estimate ($0.0075).

The CMRS Providers stated that witness Conwell's estimate included $0.0010 for cable and $0.0012 for transmission equipment. The CMRS Providers noted that the cable cost reflected Randolph's actual cable length as given in response to a data request (6.61 miles), a liberal cable cost per foot ($4.67/foot), an annual cost factor based on MebTel financial reports (a similarly situated company), the actual utilization of cable fibers for Randolph (62 percent) (again based on responses to data requests), and a liberal (low) utilization assumption for the transport system (33 percent). The CMRS Providers maintained that, in comparison, the cable cost reflected in Randolph's $0.075 per-minute transport costs is $0.0018.[1] The CMRS Providers argued that this means that the cable cost components of transport in Randolph's study and witness Conwell's testimony are different, but not extraordinarily different.

The CMRS Providers maintained that the transmission equipment cost estimated by witness Conwell of $0.0012 per minute was based on transmission equipment investment sponsored in other arbitrations by witness Schoonmaker ($96,138 transmission equipment per central office from the HAI 5.0a model), an annual cost factor from MebTel, and again a liberal (low) transport system utilization level (33 percent).

The CMRS Providers asserted that the transmission equipment cost reflected in Randolph's $0.075 per-minute transport cost is $0.0057 per minute, or 4.8 times witness Conwell's estimate.[2] The CMRS Providers maintained that, since there are three variables affecting transmission equipment cost – transmission equipment investment, annual cost factor, and transport system utilization – one or more of these factors would have to be extraordinarily unusual to cause Randolph to have such a high transmission equipment cost per minute (a cost greater than MebTel's entire transport and termination cost after corrections pursuant to the *RAO*).

The CMRS Providers stated that they attempted to bring this situation to light by developing specific issues for each of the variables underlying Randolph's transport costs, but the *RAO* considered the issues "moot" once it made the sweeping acceptance of the Randolph study methodology using the NECA average schedule formulae.

(ii) Disparity Between Randolph's and MebTel's Transport Costs

[1] Witness Schoonmaker Rebuttal Testimony, Exhibit RCS-4.

[2] *Id.*

The CMRS Providers noted that Randolph's transport cost estimate of $0.0075 per minute is 4.7 times greater than MebTel's transport cost of $0.0016 per minute.[1] The CMRS Providers argued that nothing in the record suggests, supports, or explains a transport cost for Randolph 470 percent greater than MebTel's.

(iii) Disparity in Randolph's and MebTel's Ratios of Switching Cost to Transport Costs

The CMRS Providers contended that another indication that Randolph's transport costs are inflated can be seen by comparing Randolph's ratio of switching-to-transport costs to the same ratio for MebTel. The CMRS Providers noted that, after adjustment as required by the *RAO*, MebTel's switching cost of $0.0036 per minute is 2.3 times greater than its transport cost. The CMRS Providers stated that, by contrast, Randolph's switching cost (after adjustment as required by the *RAO*) is $0.0042, which is only 56 percent of its transport cost. The CMRS Providers asserted that, when the modifications described earlier are made, Randolph's switching cost will be an even smaller fraction of its transport costs. The CMRS Providers argued that, given that MebTel's transport costs reflect its own network and financial records, whereas Randolph's transport costs are based on the NECA average schedule formulae, this raises serious questions about whether the NECA formulae are appropriate for estimating Randolph company-specific costs. The CMRS Providers stated that absolutely nothing in the record explains this striking difference.

(iv) Claimed Costs Significantly Greater Than Interstate Access Rates for Transport

The CMRS Providers stated that the information above indicating that Randolph's transport cost is grossly overstated is part of the record in this arbitration. The CMRS Providers maintained that there is one other indication (of which the Commission may take judicial notice) that Randolph's transport costs are inflated; this can be found by examining the interstate access rates Randolph charges for the same functions used to transport mobile-to-land traffic.

The CMRS Providers asserted that interstate rates for transport used by Randolph can be found in NECA Tariff 5, a publicly available document that the Commission may judicially notice.[2] The CMRS Providers maintained that the following are the computations of the transport access charges applicable to Randolph:

Line No.	Description	Amount
1.	Tandem switched transport – tandem switched facility per minute-mile	$0.000192
2.	Miles/circuit	6.61
3.	Tandem switched facility charge/minute	$0.000127
4.	Tandem switched transport – tandem switched termination per minute-termination	$0.000945
5.	Terminations	1
6.	Tandem switched termination charge/minute	$0.00095

[1] Skrivan Rebuttal, MTS Rebuttal Exhibit 2.

[2] www.neca.org/source/NECA_Home.asp. The Commission notes that the current NECA Tariff 5 is 1,211 pages.

The CMRS Providers stated that Randolph's interstate access charge for transport (rounded) would be $0.0022 per minute (0.00127 + 0.00095), a figure less than one third the transport cost of $0.0075 in Randolph's cost study. The CMRS Providers maintained that the *RAO* would thus permit Randolph to charge reciprocal compensation for transport 3.3 times higher than Randolph's interstate switched access charges for the comparable service.

(v) *RAO's* Failure to Account for Randolph's High Transport Costs

The CMRS Providers argued that they clearly laid out issues that explain the extraordinary transport cost for Randolph caused by the use of NECA formulae: Matrix Issue No. 23B dealt with cable investment; Matrix Issue No. 23C addressed transport termination investment; Matrix Issue No. 23D asked for a reasonable annual cost factor; Matrix Issue No. 25B sought to identify the portion of cable costs attributable to transport systems versus other uses; and Matrix Issue Nos. 25C and 25D related to cable and transport termination utilization. The CMRS Providers argued that the *RAO's* sweeping acceptance of the Randolph cost study ensured that none of these critical issues was addressed.

The CMRS Providers contended that the *RAO* would thus leave Randolph's transport costs significantly above those of its peer, MebTel, and above the rates Randolph charges for interstate switched access.

The CMRS Providers maintained that making the corrections to Randolph's cost study recommended by witness Conwell for each of the issues enumerated above would result in a transport cost per minute of $0.0022 per minute, a figure that is slightly higher than MebTel's study result and comparable to Randolph's interstate switched access charges. The CMRS Providers argued that the *RAO* simply missed all of this.

The CMRS Providers asserted that all of these factors, based upon record evidence and publicly available data, indicate that Randolph's cost study significantly overstates transport costs. The CMRS Providers opined that it would be arbitrary and capricious for the Commission to establish a transport rate for Randolph so clearly out of line with the facts.

The CMRS Providers maintained that the Commission should therefore adopt witness Conwell's recommendation to set Randolph's transport costs at $0.0022 per minute, which is also Randolph's interstate access rate for transport.

The CMRS Providers further maintained that the Commission's *Modification Order* required Randolph's cost study to comply with several criteria, including:

> The cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic.[1]

The CMRS Providers asserted that one of their major criticisms in this docket is that it is impossible to understand how Randolph Telephone Company derived its investment figures for switching and transport. The CMRS Providers argued that the Commission, in rejecting this

[1] See, e.g., *RAO*, page 67.

concern, stated in the *RAO* that it "has been able to calculate" the Randolph Telephone Company's original revised rate of $0.01918 per minute by application of the following formulae:[1]

1.	Traffic Sensitive Settlement – ROR Adjusted Exhibit RCS-4, Line 30	$ 31,267.00
2.	Projected Monthly LSS Revenue Exhibit RCS-4, Line 35	$ 17,707.00
3.	Traffic Sensitive Cost Line 1 – Line 2	$ 13,560.00
4.	Projected Interstate Access Minutes Exhibit RCS-4, Line 1	707,012.00
5.	Traffic Sensitive Cost Per Minute of Use – Line 3/Line 4	$ 0.01918

The CMRS Providers noted that the primary value in Randolph's study (shown on the first line of the chart) is $31,267.00, which can also be found in Confidential Exhibit RCS-4 of the Rebuttal Testimony of Randolph witness Schoonmaker. The CMRS Providers maintained that, as can be seen, Randolph's proposed rate of $1.918 cents per minute (the rate proposed prior to reducing the usage-sensitive percentage for local switching following a review of Randolph's CPRs is derived through a simple arithmetical progression from that initial amount.

The CMRS Providers asserted that the $31,267.00 value cannot be verified. The CMRS Providers argued that neither the Commission nor the CMRS Providers knows anything at all about that value, other than it was derived from NECA formulae and from data taken from companies other than Randolph. The CMRS Providers maintained that the data used in the formulae, the companies from which the data were derived, the constants in the formulae, the variables, and the form of the equations themselves is not contained in the record.

The CMRS Providers noted that witness Schoonmaker, when questioned about his use of NECA data and formulae, stated:

> There's pages and pages of data in that that shows each study area, their costs and so forth. So the kind of data that is available for MebTel is also available for the average companies in the NECA average schedule sample.[2]

The CMRS Providers further noted that witness Schoonmaker, when asked if the data that he was referring to could be found in his testimony, stated:

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[1] *RAO*, page 69.
[2] Hearing Transcript, Vol. II, page 148, lines 1 through 5.

> It's not in my testimony. It's referred to in my testimony. It's a 600-page document.[1]

The CMRS Providers asserted that neither the NECA 600 page document, the NECA data, nor the NECA formulae are contained in witness Schoonmaker's testimony or elsewhere in the record.[2]

The CMRS Providers noted that the Randolph cost study violates not only the Commission's previous *Modification Order* but also FCC decisions requiring that cost studies be verifiable. The CMRS Providers maintained that the FCC has specifically held that:

> Any data used to estimate costs should either be derived from public sources, or capable of verification and audit without undue cost or delay.[3]

> All data, formulas, and other aspects of the models must be made available to other parties for their evaluation. In other words, a cost model must be transparent and verifiable.[4]

The CMRS Providers contend that the Commission's *Modification Order* did not purport to abrogate these requirements. The CMRS Providers further argued that, under the federal law that the Commission is required to apply in this case, cost studies that cannot be verified, such as Randolph's, are not acceptable for establishing transport and termination rates.

The CMRS Providers noted that they had suggested methods by which Randolph's cost study could be modified to achieve a reasonable and lawful result. The CMRS Providers stated that, however, the fact remains that Randolph's study cannot be verified. The CMRS Providers asserted that, if the Commission does not correct the errors discussed above, the CMRS Providers will be left with no choice but to ask a federal court to disqualify Randolph's study entirely and start the process over again – this time in compliance with federal law.

The CMRS Providers maintained that, at this stage of the arbitration, they are focused on what should be an obvious outcome with respect to Randolph's transport and termination rate. The CMRS Providers noted that Randolph's embedded switching cost following modifications required by the *RAO* is $0.0042. The CMRS Providers stated that, as described previously, this figure must be adjusted to comply with Guidelines in the *Modification Order*. The CMRS Providers contended that these adjustments will produce a switching cost of no more than witness Conwell's forward-looking estimate of $0.0023 per minute.

The CMRS Providers stated that witness Conwell's estimate of forward-looking transport costs, which was ignored by the Commission, should be adopted and equals $0.0022 per minute;

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[1] *Id.*, lines 7 through 8.

[2] *Id.*, lines 9 through 10.

[3] *Virginia Arbitration Cost Order*, 18 FCC Rcd 17722, 17747 Paragraph 48 (2003).

[4] *Id.* At 17742-43 Paragraph 38.

this amount is slightly higher than MebTel's own estimate of its transport costs, but equal to Randolph's interstate access rate for transport. The CMRS Providers further stated that the signaling cost may remain at $0.0018 per minute.

The CMRS Providers asserted that these three costs result in a transport and termination rate of $0.0063 per minute. They noted that this amount (which is higher than MebTel's costs of $0.0051 after the modifications required by the *RAO*, or $0.0046 after MebTel's embedded switching investment has been reduced by 12 percent) is the maximum Randolph should be allowed to charge in the form of reciprocal compensation.

The CMRS Providers stated that under no circumstances should Randolph be allowed to charge a rate three times greater than MebTel's.[1] The CMRS Providers argued that absolutely nothing in the record supports such an outcome.

NON-PARTY COMMENTS

EMBARQ: Embarq did not comment on these Findings of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not comment on these Findings of Fact.

VERIZON WIRELESS: Verizon Wireless did not comment on these Findings of Fact.

INITIAL COMMENTS

RLECs: The RLECs stated that the CMRS Providers accused the Commission of having "decline[d] to address the specific issue raised by the CMRS Providers about Randolph's cost study and its compliance (or lack thereof) with the Guidelines . . . ." The RLECs noted that the CMRS Providers allege that this amounts to "reversible error," accusing the Commission of failing to take the CMRS Providers' evidence into account. The RLECs asserted that, as shown by the Commission's recitation and discussion of the evidence on pages 62 through 97 of the *RAO*, the Commission thoroughly considered the CMRS Providers' evidence and arguments concerning various aspects of Randolph's cost study. The RLECs maintained that the CMRS Providers are wrong in accusing the Commission of having ruled "without apparent critical evaluation of the evidence."

The RLECs maintained that the CMRS Providers then proceed to rehash the many adjustments which they proposed be made to Randolph's alternative cost study in their Brief and Proposed Order. The RLECs noted that the CMRS Providers started by proposing the switch cost shown by Randolph's alternative cost study by 12 percent, and then proposed to further reduce that amount by making an additional adjustment to "reflect a more efficient level of utilization." The RLECs asserted that the Commission properly rejected the CMRS Providers' evidence and argument on this point in reaching the decisions reflected in the *RAO*.

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[1] Randolph's claimed costs of $0.014/minute are approximately three times higher than MebTel's costs of $0.0052/minute, after making the adjustments required by the *RAO*, or $0.0047/minute, after MebTel's switching investment has been reduced by 12 percent.

The RLECs stated that, in addition, the NECA cost data upon which Randolph's proposed rate is based does not include investment data solely from 1999, but instead relies upon switch investments for the sampled companies through 2003 and 2004. The RLECs maintained that, thus, it is not appropriate to apply that factor to the Randolph rate, which is based on this later data.

The RLECs asserted that the CMRS Providers' argument as to the alleged decline in switch pricing is, effectively, that the Commission has no choice but to accept witness Conwell's testimony on this point. The RLECs argued that, for any number of reasons, the Commission could reject the evidence offered by the CMRS Providers as to alleged decline in switch costs. The RLECs maintained that these reasons could include the lack of any ability to verify the accuracy and applicability of the AUS Price Index data, the fact that witness Conwell's opinion is premised on the hearsay testimony of a witness in Tennessee, or the fact that the Commission concluded that the CMRS Providers' evidence was insufficient to establish their position on this point. The RLECs argued that merely because a party offers evidence on a point in a proceeding before the Commission does not mean that the Commission is required to find the evidence to be credible, persuasive, or sufficient.

The RLECs noted that, according to N.C.G.S. 62-65(a), the Commission, "when acting as the court of record [shall] apply the rules of evidence applicable to civil actions in superior court, insofar as practicable . . . ." The RLECs asserted that, as such, the Commission is free to weigh the evidence and exercise judgment with respect to its credibility. *State ex. Rel. Utilities Commission v. Fredrickson Motor Express*, 232 N.C. 180, 59 S.E. 2d 582 (1950). The RLECs stated that the credibility and weight to be given evidence are for the Commission to decide. *State ex. rel. Utilities Commission v. Thornburg*, 316 N.C. 238, 324 S.E. 2d 28 (1986). The RLECs argued that the Commission is not required to comments on every single fact or item of evidence presented by a party. *Dennis v. Duke Power Co.*, 114 N.C. App. 272, 442 S.E. 2d 104 (1994), *modified on other grounds*, 341 N.C. 91, 459 S.E. 2d 707 (1995). The RLECs maintained that it is presumed that the Commission gave proper consideration to all competent evidence presented. *State ex. rel. Utilities Commission v. Thornburg*, 316 N.C. 238, 324 S.E. 2d 28 (1986) ["In the absence of an express statement by the Commission to the contrary, some record evidence to the contrary, or a summary disposition which indicates to the contrary, we must presume that the Commission gave proper consideration to all competent evidence presented." *Id]*. The RLECs asserted that, accordingly, just because their arguments on switch cost did not carry the day with the Commission, as the CMRS Providers would have hoped, that fact "cannot be said to be an indication that the Commission failed to accord [their] evidence the proper amount of consideration." *Id*

The RLECs noted that, with regard to the proposed CMRS Providers' adjustment to Randolph's investment to "reflect a more efficient level of utilization," an RLEC such as Randolph with an existing network has no ability to instantly create a more efficient network or to downsize its network investment if demand decreases. The RLECs maintained that the Commission recognized this reality in alternative cost study Guideline 2, which provides that "cost data . . . should reflect an efficient network to **the extent practicable**." (emphasis added). The RLECs stated that the alternative cost study approach Randolph used does reflect an "efficient network to the extent practicable." The RLECs argued that, by including the "to the extent practicable" qualification, the Commission's alternative cost study Guidelines afford the RLECs flexibility they would not have had under the FCC's TELRIC cost studies and pricing and that these Guidelines allow use of reasonable surrogates for RLEC costs. The RLECs stated that the Commission has excused them from providing TELRIC-compliant cost studies and that they have likewise been excused from the burden of developing their costs based on a hypothetical network. The RLECs maintained that the CMRS Providers' argument on page 36 of their Objections that rates should be based not on existing demand, but rather on some other unnamed standard, is contrary to long-standing rate making processes used by this and other Commissions. The RLECs argued that, if costs were determined based on some higher hypothetical level of demand, then that decision would assure that Randolph would not be able to recover its cost of providing service.

The RLECs argued that "to the extent practicable" is not the same as "an absolute requirement". The RLECs noted that the CMRS Providers argued that Randolph made no showing that the use of forward-looking costs was not practicable for it. The RLECs stated that they argue that the use of NECA data in Randolph's cost study was flawed from the outset because that approach involved the use of embedded cost data.

The RLECs asserted that the CMRS Providers are so wedded to their position on each point to which they object that they routinely describe the *RAO*'s failure to embrace their position as being "arbitrary and capricious." The RLECs argued that, to be arbitrary and capricious, the Commission would have had to have acted "patently in bad faith", "whimsically", or without "fair and careful consideration." *Lewis v. N.C. Dep't of Human Resources, supra.*

The RLECs noted that the CMRS Providers also criticized the *RAO*'s findings regarding Randolph's transport costs, asserting that the transport cost developed using the NECA formulas is "grossly overstated" in relationship to witness Conwell's cost estimate. The RLECs maintained that, in support of this characterization, the CMRS Providers make comparisons between Randolph's and MebTel's transport rates, Randolph's costs, and the interstate access rates that Randolph charges.

The RLECs asserted that the variation between the transport costs of Randolph and MebTel, while not insignificant, is not necessarily unusual due to differences between the companies' operating territories and the different cost methodologies used in arriving at their estimated costs. The RLECs stated that it is not unusual for individual companies to have substantial differences in individual cost elements due to their different circumstances.

The RLECs maintained that the comparison that the CMRS Providers make between the ratios of the switching rate to the transport rate is of even less value. The RLECs stated that the factors that impact switching costs (number of switches, access line per switch, and minutes of use per switch) differ substantially from that factors that impact transport costs (transport mileage, differences in geography and construction costs, and usage per circuit.) The RLECs noted that, based on variations in these factors, it would not be at all unusual to see substantial variations between the ratio of switch costs to transport costs between companies.

The RLECs further commented that, in regard to the comparison between Randolph's costs and the interstate transport rate that it charges, large differences are also not unexpected. The RLECs noted that Randolph's costs are based on the costs of average schedule companies, a subset of the total companies participating in the NECA interstate pooling and tariff process. The RLECs explained that the tariff rates developed and filed by NECA are based on average costs for all pool participants and individual company cost characteristics. Figures for individual company usage, mileage, and usage density routinely cause individual company results to differ substantially from the average of the total (both higher and lower). The RLECs asserted that, as would be expected from any pooling/averaging process, individual companies may be either net recipients or contributors to the NECA pool.

The RLECs argued that, to the extent that the CMRS Providers compare the transport expense shown in Randolph's cost study to the NECA interstate access tariff component for transport, it is appropriate to note that NECA's interstate access rate per minute for switching is $0.017105, while Randolph's alternative cost study yields a switching cost of $0.00614 per minute. The RLECs maintained that the simple truth is that the rate for each function is higher/lower from one source than from the other, depending on the functionality involved and the individual company costs in comparison to the average for the total pool. The RLECs stated that the transport rate yielded by Randolph's alternative cost study is higher (approximately 3.4 times higher, as the CMRS Providers point out). The RLECs noted that, conversely, the switching rate yielded by Randolph's study is $0.00614, which is 36 percent of Randolph's $0.017105 per minute switching rate under NECA's interstate access tariff. The RLECs asserted that if comparison to the interstate access pricing for the same functions is valid, then to the extent the former suggests that Randolph's cost study overstates its transport cost, the later suggests with equal force that Randolph's cost study understates its switching cost.

The RLECs stated that in footnote 115 of the CMRS Providers' Objections, they complain that the total costs shown by Randolph's study are three times higher than the costs that the *RAO* would yield for MebTel (before any revision of the *RAO* addressing MebTel's Objection). The RLECs asserted that it is somewhat ironic that the CMRS Providers would compare the relative level of those costs. The RLECs noted that, first, as a practical matter, costs will vary widely between companies depending on their specific circumstances. The RLECs maintained that, second, the two companies used different alternative cost study methodologies, which is consistent with the flexibility afforded the RLECs under the *Modification Order*. The RLECs noted that, third, to the extent inter-ILEC comparisons are appropriate, it is quite ironic that the CMRS Providers advance this complaint when they have recently entered into interconnection agreements with other small North Carolina ILECs, comparable in size and in other ways to Randolph and Ellerbe, which resolve all these issues and which provide for payment of reciprocal compensation of $0.015 per minute.

The RLECs noted that the CMRS Providers also charge that the Commission's failure to embrace their proposed revisions to Randolph's transport costs "leave Randolph's transport costs significantly above its peers and the rates Randolph charges for interstate switch access." The RLECs asserted that, while Randolph's transport costs are above the interstate switched access rate for transport, the same is not true of Randolph's overall transport and termination rate. The RLECs maintained that Randolph's interstate access rate for switching and transport combined, as set forth in NECA Tariff 4, is $0.019305 per minute ($0.017105 for local switching plus $0.0022 for transport). The RLECs stated that this is what Randolph charges an interexchange carrier to terminate a minute of interexchange traffic. The RLECs noted that the CMRS Providers concede that the network functions used to terminate a minute of interstate interexchange traffic are basically identical to the network functions used to terminate a minute of CMRS-originated traffic. The RLECs asserted that, as shown by Randolph's recently filed Amended Report on Joint Review of Continuing Property Records, compliance with the *RAO*'s directives that Randolph re-run its cost study using the most recent NECA formulae, that the parties jointly review Randolph's CPRs, and using Randolph use the most current usage data yields a reciprocal compensation rate of $0.01362, which is not higher than its interstate terminating access rate of $0.019305.

The RLECs opined that it is ironic that the CMRS Providers would make any reference to how Randolph's transport cost compares to the rate for its "peer" MebTel. The RLECs asserted that, if comparisons to the costs and rates of peers are relevant, then the Commission should duly note that the CMRS Providers have recently agreed to pay the RLECs' peers reciprocal compensation of $0.015 per minute, which is more than three times the rate they propose to pay Randolph. The RLECs stated that this outcome is made all the more ironic by the fact that the CMRS Providers pay even higher rates to other North Carolina ILECs which are not comparable to Randolph, such as the $0.0175 per minute rate that AT&T pays to Concord Telephone Company; Concord is many, many times larger than Randolph or Ellerbe.

The RLECs noted that the CMRS Providers criticize Randolph's use of NECA average schedule formulas and data in its costs study, arguing that this information is not verifiable. The RLECs asserted that the NECA filing utilized by Randolph witness Schoonmaker is a publicly available document, and as shown in his testimony, it is available through the FCC's website at http://gullfoss2.fcc.gov/prod/ecfs/retrieve.cgi?native_or_pdf=pd&id_document=6518191773. The RLECs stated that the CMRS Providers' assertion that this NECA filing lacks verifiable data is unsustainable; a review of this NECA filing, readily accessible by the link shown in witness Schoonmaker's testimony, establishes that this claim is not true. The RLECs maintained that NECA filed this 610 page document with the FCC in 2006 and that this filing describes in detail the steps taken and the data used by NECA to arrive at the average schedule formulas it proposed to the FCC. The RLECs noted that, in the introductions to that filing, NECA makes the following statement:

> Each of the steps followed in NECA's study are explained in detail in this Filing. Section II describes the statistical sampling methods that NECA used in its data collection for settlement formula development. Section III contains a description of the sources and types of data NECA collected from cost and average schedule companies. Section IV explains the methods NECA used to develop cost allocation factor models from sample cost company data. Section V describes how NECA projected growth in historical cost and demand data, to develop cost and demand data applicable to the period the proposed formulas will be in effect. Section VI explains how NECA calculated Interstate and Access Category costs by account for each sample average schedule

> study area. Section VII explains how NECA develops the 'best fitting' mathematical formulas for use in determining settlements, and explains how the proposed formulas will affect average schedule companies. Section VIII lists the current and proposed average schedule formulas. Finally **the attached appendices contain all the data used in NECA's study. These data enable the Commission and interested parties to verify NECA's Study results.** (Emphasis added.) page I-4.

The RLECs asserted that a review of the Appendices included in this NECA filing shows that detailed cost data is included. The RLECs stated that, for example, Appendix B-1 contains detailed investment and expense data for all 192 cost companies in NECA's sample, including Central Office Equipment investment detailed in individual COE separations categories and by interstate access category; Appendix D-2 contains demand data, including access lines and interstate access minutes, for those same companies; Appendices C-1 through C-5 contain average schedule cost and expense data by FCC-established accounts for three different years; and Appendix D-1 includes demand data for each of the sampled average schedule companies, including access line and interstate access minutes. The RLECs maintained that, while it might be time consuming to summarize and analyze this data, the data is available so that any party truly interested in doing so can, in fact, "verify the NECA study results."

The RLECs stated that, in reviewing the data witness Conwell proposes, one finds that the criticisms he applies to the NECA study apply with even greater force to that information. The RLECs maintained that, specifically, witness Conwell relies on data taken from the *USF Inputs Order*, which data he then proposes to adjust based on the AUS Price Index. The RLECs asserted that the CMRS Providers produced no evidence concerning the data underlying the *USF Inputs Order*. The RLECs maintained that, likewise, the AUS Price Index, which witness Conwell relied on to reduce the non-rural switch cost estimates from the levels shown in the *USF Inputs Order*, is similarly not verifiable by any evidence provided by the CMRS Providers nor is it publicly available. The RLECs stated that, while they do not doubt the FCC's ability to collect and collate data, the truth is that the data that witness Conwell relies on is not verifiable, as required by the Commission's alternative cost study Guidelines. The RLECs asserted that, given the wealth of information set forth in the 610 page NECA filing and the fact that the FCC reviewed and approved that filing, the data from the *USF Inputs Order* and AUS Index data are nowhere near as verifiable as the NECA data that Randolph used in its cost study. The RLECs concluded that, in short, the arguments the CMRS Providers now present to the effect that the NECA cost study data is not verifiable, and by inference that the data witness Conwell used is more verifiable, is not supported by the record.

CMRS PROVIDERS: The CMRS Providers addressed Randolph's proposal to update its cost study to include the most current information on Randolph's access lines and projected usage. The CMRS Providers noted that Randolph's initial cost study projected 707,012 interstate access minutes and 4,446 access lines. The CMRS Providers maintained that Randolph now seeks to change those values to 610,415 and 4,252, respectively.

The CMRS Providers asserted that the *RAO* originally approved Randolph's use of embedded cost data because the alternative cost study does use embedded costs to some degree with forward-looking demand units. The CMRS Providers maintained that Randolph's nominal use of forward-looking demand units did not cause its original cost estimate to be forward-looking; instead, its use actually exacerbated the overestimation of costs already inherent in the study due to the use of embedded costs.

The CMRS Providers stated that they are willing to stipulate that Randolph's minutes of use and lines in service are declining; however, these alleged facts are irrelevant to the proper standard to be applied in this case under both the FCC's Rules and the Commission's Guidelines. The CMRS Providers argued that the proper standard requires that minutes of use be efficient in relation to Randolph's network. The CMRS Providers asserted that dividing past, sunk switching costs by declining demand, as was done in Randolph's original cost study, sharply raises Randolph's switching costs per minute. The CMRS Providers stated that Randolph now seeks to compound this error even further by once again updating projected minutes to values significantly lower than the original projected values. The CMRS Providers maintained that, all other things being equal, this change further raises Randolph's impermissible (embedded) cost estimate by 16 percent (16 percent = 707,708 / 610,415 – 1).

The CMRS Providers stated that the cost to purchase and install switching systems has dropped substantially in the past twenty years, meaning that the RLECs' forward-looking switching investments are not as great as the investments on their books. The CMRS Providers asserted that, thus, the argument is sometimes made by RLECs that, because rates based on forward-looking costs do not allow them to recover their actual costs, they must be allowed to incorporate other measures into their studies to offset this loss. The CMRS Providers maintained that this is the approach apparently taken by Randolph in requesting to once again lower its claimed forward-looking demand units.

The CMRS Providers argued that, under the Act and the cost study Guidelines adopted by the Commission, rates for transport and termination allow incumbent carriers to recover costs they would incur today to provide transport and termination, rather than costs incurred in the past, but which are now sunk. The CMRS Providers maintained that recovery of past plant investments is allowed under the old rate base paradigm, but not under the Act. The CMRS Providers asserted that, under the Act, rates for transport and termination are established to recover expected future costs as in other competitive markets.

The CMRS Providers noted that the Supreme Court has recognized this policy shift, commenting that the Act is:

> [R]adically unlike all previous statutes in providing that rates be set 'without reference to a rate-of-return or other rate based proceeding,' §252(d)(1)(A)(i). The Act thus appears to be an explicit disavowal of the familiar public-utility model of rate regulation (whether in its fair-value or cost-of-service incarnations) presumably still being applied by many States for retail sales . . . in favor of novel rate setting designed to give aspiring competitors every possible incentive to enter local retail telephone markets.[1]

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[1] *Verizon Communications, Inc. v. FCC*, 535 U.S. 476, 489, 122 S. Ct. 1646, 152 L. Ed. 2nd 701 (2002) (*Verizon Communications*).

The CMRS Providers stated that, for firms in competitive industries, market forces establish prices, not levels of historical investment. The CMRS Providers noted that this is the underlying rationale for establishing transport and termination rates. The CMRS Providers maintained that, for this reason, in determining transport and termination rates, state regulators must set aside the tenets of rate base regulation.

The CMRS Providers noted that the Commission's Guidelines did not purport to suspend the requirement that Randolph's transport and termination rates comply with these provisions of federal law. The CMRS Providers opined that, instead, the Guidelines required Randolph's cost study to be forward looking and reflect an efficient network to the extent practicable.

The CMRS Providers argued that the standard of practicability clearly applied to the burdens surrounding collection of data and not to the application of federal cost rules. The CMRS Providers maintained that, if the Commission had intended that the RLECs did not have to comply with federal rules, specifically the rules requiring the use of forward-looking costs, then the Guidelines could and would have said so; however, they did not contain such an assertion. The CMRS Providers asserted that a far more reasonable interpretation of the Guidelines is that relief from the federal standard is warranted only to the extent it is established that the data collection burdens associated with meeting the federal standard render compliance with it impracticable.

The CMRS Providers noted that federal standards, as well as the Commission's Guidelines, require both the use of forward-looking costs and the assumption of an efficient network. The CMRS Providers stated that embedded plant investments and costs often do not reflect the required efficient utilization. The CMRS Providers maintained that, if existing plant is not efficiently utilized, costs per unit of demand (e.g., per minute of use in this case) include the costs of spare, unused capacity. The CMRS Providers argued that, by allowing Randolph to lower its estimates of minutes of use, the Commission would be requiring the CMRS Providers to pay rates that recover embedded, sunk investment in excessive, unused, spare capacity.

The CMRS Providers stated that the FCC Rules and the Commission's Guidelines both address this issue. The CMRS Providers maintained that Guideline 2 requires that Randolph's cost study reflect an efficient network to the extent practicable and that the FCC Rules require transport and termination cost studies to assume the use of the most efficient technology for reasonably foreseeable capacity requirements. The CMRS Providers asserted that the FCC adopted this approach because it encourages facilities-based competition to the extent that new entrants, by designing more efficient network configurations, are able to provide the service at a lower cost than the ILEC.

The CMRS Providers opined that, in estimating transport and termination costs, therefore, both federal law and the Guidelines require a cost study to model a network sized to service expected total demand and to allow an efficient and reasonable level of spare capacity for future growth and administration of the network. The CMRS Providers argued that, to avoid the impracticability of onerous data gathering, Randolph may utilize appropriate surrogate information, but the basic requirement of efficiency still applies.

The CMRS Providers noted that witness Schoonmaker's original Confidential Exhibit RCS-2 indicated that, from mid-2004 to mid-2005, Randolph's switching plant was handling 721,800 monthly interstate minutes or 18 percent more usage than in the latest updated data (18 percent = 721,800 / 610,415 – 1). The CMRS Providers argued that Randolph's switching plant was, therefore, more efficiently utilized from mid-2004 to mid-2005 than it apparently is today. The CMRS Providers asserted that to comply with the efficient network requirement of the Guidelines and the Act, Randolph's projected minutes of use are more appropriately established using mid-2004 to mid-2005 levels. Allowing Randolph to decrease projected minutes and then apply those minutes to embedded costs would directly violate the Guidelines and the Act.

ALLIANCE: The Alliance did not address these Findings of Fact in its initial comments.

EMBARQ: Embarq did not address these Findings of Fact in its initial comments.

PUBLIC STAFF: The Public Staff noted that Randolph did not object to these Findings of Fact, but now requests that the Commission revisit and clarify its Findings and direct Randolph to also update the number of access lines and projected usage. The Public Staff maintained that Randolph stated that, if it would be both appropriate and logical for it to update its cost study to incorporate the latest NECA formulae, the updated study should also reflect updated access lines and projected usage data as well. The Public Staff agreed.

The Public Staff noted that, according to Randolph, the impact from using updated NECA formulae has been provided to the CMRS Providers and that, additionally, Randolph provided them with the updated access line and projected usage data. The Public Staff noted, as did Randolph, that it was unsure whether the CMRS Providers objected to use of the updated access line and projected usage data.

The Public Staff stated that it believes that Randolph's request for clarification should be granted. The Public Staff asserted that the Commission should modify its finding to indicate that Randolph's updated alternative cost study should also reflect current access line and projected usage data as proposed by Randolph.

The Public Staff also noted that the CMRS Providers objected to Findings of Fact Nos. 11 and 12. The Public Staff stated that the CMRS Providers argued that the use of embedded costs is impermissible under FCC rules and the *Modification Order*. The Public Staff argued that the Commission considered this assertion in the *RAO*. The Public Staff maintained that, in the *RAO*, the Commission noted that Guideline No. 2 allowed the use of a surrogate for a company's cost, but the resulting cost study should produce costs that were forward looking and reflected an efficient network to the extent practicable. The Public Staff asserted that Guideline No. 2 does not prohibit the use of embedded costs in the cost studies and that the Commission concluded that Randolph's cost study did not violate Guideline No. 2.

The Public Staff further noted that the CMRS Providers argued, as they did in their Objections to Finding of Fact No. 8 regarding MebTel's cost study, that the Commission should have accepted witness Conwell's recommendations regarding Randolph's cost study. The Public

Staff stated that it believes that Randolph's cost study conforms to the cost study Guidelines approved in Docket No. P-100, Sub 159. The Public Staff maintained that, for the reasons set forth in its initial comments on the CMRS Providers' Objection to Finding of Fact No. 8, the Commission should deny the CMRS Providers' request to adjust the cost studies as the CMRS Providers recommend,

REPLY COMMENTS

RLECs: The RLECs noted that the CMRS Providers argued that Randolph should not be allowed to update its minutes of use and line estimates because such estimations do not reflect an efficient use of their network given that the existing network could handle a greater number of minutes. The RLECs argued that what the CMRS Providers do not take into consideration in their analysis is the efficiency that is gained by using assets over a long period of time. The RLECs asserted that, while switch prices may have declined somewhat over a period of time and while the cost of a new switch may now be less, it is not efficient to replace a switch every two or three years just because the price of a new switch has declined somewhat as compared to continuing to use a switch, purchased at a somewhat higher price, but available for use over a fifteen year life. The RLECs maintained that, given the considerable capital costs of a switch, the overall cost of using a higher priced switch for fifteen years is less than the cost of using several switches for only three or four years each, even if the price of each new switch is less than the previous one.

The RLECs maintained that the CMRS Providers' arguments regarding the efficient use of Randolph's switch in light of present day volumes need to be tempered with the knowledge of the extended period of time that Randolph has kept its switch in service. The RLECs noted that the action that the CMRS Providers urge, in the name of efficiency, is that Randolph buy a new switch every time the FCC orders ILECs to deploy another switch functionality or every time the switch vendor issues a software upgrade. The RLECs stated that, while this approach would be the picture of inefficiency, it is the absurd result of the approach that the CMRS Providers urge.

The RLECs stated that the Commission's alternative cost study guidelines provide that RLEC cost studies shall be forward looking and reflect an efficient network to the extent practicable. The RLECs noted that the CMRS Providers now attempt to explain away the phase "to the extent practicable" as merely relating to the burden associated with the collection of data for the cost study. The RLECs further stated the CMRS Providers now argue that this "practicability" qualification relates only to data collection and is of no relevance to the applicability of the TELRIC requirement to use forward looking cost data and to assume a perfectly albeit hypothetically efficient network. The RLECs argued that this stained construction is yet another attempt by the CMRS Providers to interpret the Commission's alternative cost study guidelines as essentially identical to the FCC's TELRIC regulations. The RLECs argued that this restrictive construction fails because it would effectively render the *Modification Order* pointless and deprive the RLECs of the very flexibility that the FCC's TELRIC requirements do not provide and which the Commission sought to make available to the RLECs.

The RLECs stated that Randolph's request to be allowed to update its usage data, as part of producing the updated cost study required by the *RAO*, is reasonable. The RLECs noted that the Public Staff supports Randolph's request, agreeing it would be appropriate and logical for Randolph, when revising its cost study to use the most current NECA formulae, to also utilize updated access lines and projected demand data. The RLECs requested that the Commission grant Randolph's request and allow it to use the updated data provided in Randolph's Confidential Spreadsheet 2 as part of the updated cost study required by the *RAO*.

CMRS PROVIDERS: The CMRS Providers stated that they have previously pointed out that the wide disparity between the rates approved by the Commission for Randolph and MebTel creates a strong inference that Randolph did not use appropriate data or an appropriate methodology in its cost study. The CMRS Providers noted that the RLECs stated in their initial comments that the disparity may be due to the differences between Randolph's and MebTel's operating territories. The CMRS Providers maintained that the RLECs have presented no evidence indicating the alleged differences between the companies' operating territories. The CMRS Providers argued that, in fact, as the Commission is aware, Randolph's cost study is not even based upon Randolph's operating territory or any other Randolph-specific data. The CMRS Providers stated that, instead, it is based upon the operating territories and embedded data of unnamed NECA average schedule companies and produces a result far in excess of that established through the use of MebTel's approach. The CMRS Providers asserted that the difference in the two companies' rates, as approved by the *RAO*, is not because of differences in operating territories; the difference is caused, as the RLECs themselves admit, by the different cost methodologies employed by the two companies. The CMRS Providers argued that, in the case of Randolph, the methodology was improper.

The CMRS Providers opined that perhaps the most significant defect in Randolph's study is that it cannot be verified. The CMRS Providers noted that this is a clear violation of FCC requirements as outlined in the FCC's 2003 *Virginia Arbitration Order*, which states that:

> Any data used to estimate costs should either be derived from public sources, or capable of verification and audit without undue cost or delay. [Paragraph 48]
>
> All data, formulas, and other aspects of the models must be made available to other parties for their evaluation. In other words,. a cost model must be transparent and verifiable. [Paragraph 38]

The CMRS Providers noted that, in response to this criticism, the RLECs stated in their initial comments that the NECA filing utilized by witness Schoonmaker is a publicly available document 610 pages in length that is available through the FCC's website. However, the CMRS Providers asserted, there is no evidence that the Commission reviewed the 610 page document, and it is not in the record. The CMRS Providers stated that they tried and failed to decipher the document. The CMRS Providers maintained that it is disingenuous to claim that Randolph's study properly computes costs without actually examining what has been done. The CMRS Providers noted that an opaque 610 page document not placed in the record does not meet the FCC's requirement that cost studies be transparent and verifiable.

The CMRS Providers stated that, in the case of the MebTel study, one can trace each cost value to specific inputs and determine how a particular number was arrived at. The CMRS Providers noted that, for example, it was possible, through examination of MebTel's study, to determine that MebTel was attempting to recover in its transport and termination rate the costs of a switch that was not terminating CMRS traffic. The CMRS Providers maintained that this was clearly inappropriate, and the *RAO* rightly disallowed the claim.

The CMRS Providers asserted that there is no way to make a similar analysis of the Randolph study. The CMRS Providers stated that it is impossible to determine the specific switches used to compute Randolph's claimed switching investment. The CMRS Providers stated that it is impossible to tell if those switches are or were being used to terminate wireless traffic. The CMRS Providers maintained that, since MebTel has a switch in operation that does not terminate wireless traffic, some, or even many, of the RLECs whose data are included in the Randolph study might be similarly situated--there is simply no way to tell.

The CMRS Providers stated that, as it stands, the Randolph study could be used to justify any level of costs. The CMRS Providers argued that if Randolph claimed that its costs were four cents per minute, or four tenths of one cent per minute, no one would be able to explain how either number was derived. The CMRS Providers asserted that this is a clear violation of FCC requirements.

The CMRS Providers further noted that the Public Staff supports the request of Randolph to introduce new evidence into the record more than one year after the conclusion of the hearing. The CMRS Providers stated that, near the conclusion of the hearing in this matter, the Public Staff introduced into evidence a document that the CMRS Providers had never seen before. The CMRS Providers noted that, when they sought permission to supplement the record in response to the exhibit, the Public Staff strenuously objected and the Commission denied the CMRS Providers' request.

The CMRS Providers maintained that, thus, they were denied a meaningful opportunity to comment upon the exhibit, upon which the *RAO* relies in determining that the proposed switching investments of Randolph and MebTel are reasonable. The CMRS Providers asserted that, had they been given the opportunity, they would have explained why the comparison was misleading and inaccurate. The CMRS Providers noted that, however, they were not allowed to provide such an explanation.

The CMRS Providers asserted that the Public Staff, however, now apparently sees no problem in allowing Randolph to supplement the record with new data that the CMRS Providers have not seen and have not been given the opportunity to cross examine Randolph about. The CMRS Providers noted that a fundamental requisite of the Due Process clause of the Federal Constitution "is the opportunity to be heard." *Goldberg v. Kelly*, 397 U.S. 254, 267 (1970). The CMRS Providers stated that another bedrock constitutional principle is the right of cross-examination. The CMRS Providers maintained that, thus, the Confrontation Clause of the Federal Constitution "commands, not that evidence be reliable, but that reliability be assessed in a particular manner: by testing in the crucible of cross-examination." *Crawford v. Washington*, 541 U.S. 36, 61 (2004). The CMRS Providers stated that they were denied the opportunity to be heard concerning an exhibit that the Commission found especially relevant. The CMRS Providers noted that the Public Staff now supports the introduction of evidence, a year after the closing of the record, that the CMRS Providers have not seen and cannot possibly cross examine Randolph about. The CMRS Providers argued that the issues noted above raise serious questions of constitutional concern and urged the Commission to ensure that due process of law and the right of cross-examination be denied to no party in this proceeding.

ALLIANCE: The Alliance did not file reply comments.

EMBARQ: Embarq did not address these Findings of Fact in its reply comments.

PUBLIC STAFF: The Public Staff did not file reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth did not address these Findings of Fact in their reply comments.

VERIZON WIRELESS: Verizon Wireless did not address these Findings of Fact in its reply comments.

DISCUSSION

The Commission will first address Randolph's Objections, wherein the Company requested that the Commission allow Randolph to update its number of access lines and projected usage in its alternative cost study. The Public Staff supported Randolph's request while the CMRS Providers strongly opposed the updates.

Randolph asserted that it would be both appropriate and logical, if Randolph is to update its cost study to incorporate the latest NECA formulae, to also include the most current information on Randolph's access lines and projected usage. Randolph noted that its original study reflected a projection of its access lines and access usage based on a twelve-month average of that data for the period ending July 2006, with the projections based on a percentage growth rate for that period from the previous twelve-month period.

The CMRS Providers argued that Randolph is attempting to introduce new evidence into the record more than one year after the conclusion of the hearing. The CMRS Providers maintained that they have not seen this new data previously and have not been given the opportunity to cross examine Randolph about the data. The CMRS Providers stated that its objections of this new data raise serious questions of constitutional concern, so the CMRS Providers urged the Commission to ensure that due process of law and the right of cross-examination are not denied to any party in this proceeding.

The Commission agrees with the CMRS Providers that it is inappropriate for Randolph to update its number of access lines and projected usage for the reasons outlined by the CMRS Providers. Randolph should use the number of access lines and projected usage originally used in its cost study. The Commission denies Randolph's request to reflect an updated number of access lines and projected usage in its alternative cost study.

The second issue the Commission must address in connection with Findings of Fact Nos. 11, 12, and 28 concerns the CMRS Providers' Objections. The CMRS Providers argued that Randolph's alternative cost study suffers from a number of flaws, including: (1) the switching cost data reflected in the NECA formulae represent embedded plant investment and the costs associated with this investment; (2) the current cost to purchase and install new switches, otherwise known as the reproduction cost, has declined over time – and declined substantially (12 percent since 1999 based on the AUS Price Index); embedded switching cost data are not valid surrogates for forward-looking costs; and, no matter how "practicable" it is to use the NECA formulae to compute switching costs, the results do not comply with Guideline 2; and (3) in its Ruling on Matrix Issue No. 23 (*RAO* Issue 13), the *RAO* approves Randolph's use of embedded cost data in its study, because "[t]he Commission concludes that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units." The CMRS Providers asserted that it is misguided to think that combining embedded costs with forward-looking demand will produce appropriate transport and termination costs. The CMRS Providers opined that Randolph's use of forward-looking demand units did not cause its cost estimate to be forward-looking; it merely exacerbated the original error.

The Commission first notes that, in this proceeding, it was presented with two options: (1) adopting Randolph's alternative cost study based on NECA average schedule formulae adjusted for forward-looking, company-specific demand units or (2) adopting CMRS Providers witness Conwell's proposed alternative cost study, which reflects (a) certain default input values from the HAI 5.0 model; (b) some Randolph-specific data from Randolph's study and data request responses; and (c) some data from MebTel's alternative cost study. The Commission reviewed all of the evidence and determined that Randolph's proposed alternative cost study was most appropriate and met the guidelines established by the Commission in its *Modification Order*.

The Commission notes that in its *RAO* it specifically stated on page 63, as follows:

> Further, the Commission concludes that the *Modification Order* **did not prohibit** the use of **embedded costs** in alternative cost studies. [emphasis added]

In addressing the CMRS Providers' comment that the NECA cost study alternative filed by Randolph in this case was identified by witness Schoonmaker as "not containing any forward-looking costs" before work on the cost study even began[1], the Commission notes that this argument by the CMRS Providers was considered by the Commission during its decision making in these dockets. In fact, the *RAO* specifically notes this argument on page 59. Further, witness Schoonmaker stated in his direct testimony, lines 5 through 17 on page 10, that:

> Q. Why did you base Randolph's proposed cost study on NECA's traffic-sensitive formulas?
>
> A. I discussed with Randolph several possible alternative options for developing cost information that would comply with the Public Staff's recommended cost study guidelines. After discussing those alternatives, **their relative merits, and**

[1] See Schoonmaker Cross-Examination Exhibit 3.

> **the relative expense** of developing each alternative, I used NECA's traffic-sensitive formulas as a basis for Randolph's cost study. I did so because these **formulae are well documented, easily obtainable, and produce a reasonable surrogate of Randolph's costs since they are developed using actual costs of similarly-situated rural ILECs**. Furthermore, the cost formulas undergo regular scrutiny by the FCC staff. Accordingly, with my updating of inputs to the formulas, Randolph's proposed cost study complies with the Public Staff's cost study guidelines adopted by the Commission in Docket No. P-100, Sub 159. [emphasis added.]

The Commission is not persuaded by any of the arguments advanced by the CMRS Providers in their Objections that use of NECA data is not allowed based on the *Modification Order*. These arguments were presented by the CMRS Providers (and so noted in the *RAO*) and rejected by the Commission.

The CMRS Providers asserted that the current cost to purchase and install new switches, or the reproduction cost of that equipment, has declined over time – and declined substantially (12 percent since 1999 based on the AUS Price Index); that embedded switching cost data are not valid surrogates for forward-looking costs; and, that, no matter how "practicable" it is to use the NECA formulae to compute switching costs, the results do not comply with Guideline 2. Again, the Commission specifically recognized this argument in its *RAO* and rejected it; the CMRS Providers have not provided any new and cogent arguments that have caused the Commission to reach a different conclusion here. The Commission specifically stated on page 63 of the *RAO*:

> The Commission concludes that the *Modification Order* did not require the RLECs to obtain a vendor switch quote.. The Commission is persuaded by the evidence of record that obtaining a switch quote from a vendor is not practicable for purposes of this proceeding.

The Commission notes that Guideline 2 was proposed by the Public Staff and adopted by the Commission, and it is entirely appropriate, based on the evidence of record in this proceeding, for the Commission to make the determination that Randolph's use of NECA formulae satisfies the requirements of its own Guideline 2. .

Further, as noted in the discussion in this *Order* relating to the Objections to Finding of Fact No. 8 concerning MebTel's alternative cost study, the Commission did not find the CMRS Providers' evidence of a 12 percent decline in switch costs persuasive and rejected the proposal. The Commission noted that the few sentences included in witness Conwell's testimony in support of such a reduction simply referenced the testimony of a Sprint PCS witness in a Tennessee arbitration proceeding. The Commission did not and still does not find this evidence convincing or persuasive so as to allow it to be adopted and applied to Randolph's switch costs in this proceeding.

Addressing the CMRS Providers' argument that neither the NECA 610 page document, the NECA data, or the NECA formulae are contained in witness Schoonmaker's testimony or elsewhere in the record, the Commission notes as follows:

(1) The NECA 610 page document is not in the record but witness Schoonmaker noted in his direct testimony the website where the document could be located and noted that the FCC approved NECA's proposed formulae. Witness Schoonmaker also noted in his testimony that the NECA cost formulae undergo regular scrutiny of the FCC staff.

(2) The Commission is unsure specifically which "NECA data" the CMRS Providers are referring to. Any data used to calculate the formulae are, apparently, included in the 610 page document addressed above.

(3) The NECA formulae (current average schedule formulae) were outlined in Exhibit RCS-1 (a 3-page document) attached to witness Schoonmaker's direct testimony. These formulae were used to calculate the figures shown on Exhibit RCS-2.

Guideline 1 states that "the cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic." The Commission finds that the use of NECA formulae satisfies the requirement that the cost data should be easily verifiable – the NECA formulae and inputs, as noted in the record in this proceeding, are filed with the FCC, scrutinized by the FCC and its Staff, and ultimately approved by the FCC. Again, the Commission notes that the RLECs were granted relief in the *Modification Order* from producing TELRIC studies for the purpose of calculating reciprocal compensation rates. For the purposes of this proceeding, the use of NECA formulae is sufficient to satisfy the requirement that the cost data should be easily verifiable.

Next, with respect to the CMRS Providers' comparison of MebTel's and Randolph's alternative cost studies and resulting rates[1], the Commission notes that MebTel's cost study and Randolph's cost study were calculated based on two entirely different methodologies. The Commission found in the *RAO* that both of those studies, with various adjustments, adhere to the guidelines outlined in the *Modification Order* and are appropriate and reasonable. The fact that the results differ does not concern the Commission since different, acceptable methodologies were used and since rates have been calculated for two separate companies. In addition, the Commission notes that the chart developed below also leads credence to the fact that the rates developed based on the Randolph study are, indeed, reasonable.

The Commission notes that, although Randolph's alternative cost study is not perfect, it is, on the whole, reasonable and in compliance with the *Modification Order*. The Commission simply found the evidence supporting Randolph's alternative cost study was more convincing than the evidence supporting the alternative cost study presented by witness Conwell. The Commission notes, as outlined in the table below, that, based on the totality of the evidence, the

[1] The CMRS Providers asserted, specifically, that (a) Randolph's transport cost estimate is 4.7 times greater than MebTel's transport cost; (b) MebTel's switching cost is 2.3 times greater than its transport and Randolph's switching cost is only 56 percent of its transport cost; and (c) Randolph's interstate access charge for transport is less than 1/3 the transport cost in Randolph's alternative cost study.

transport and termination rate approved by the Commission in the *RAO* for Randolph is reasonable:

Source	Rate
MebTel's approved rate per *RAO*	$0.0051
MebTel's approved rate per this Order (final rate)	$0.0067
Randolph's approved rate per *RAO*	$0.01362[1]
Randolph's approved rate per this Order (final rate)	Rate = <$0.01362[2]
Source	**Rate**
CMRS Providers' proposed rate for Randolph	$0.0063
Rate in negotiated Interconnection Agreements[3]	$0.015
Interim rate prior to this proceeding	$0.015

CONCLUSIONS

The Commission concludes that it is appropriate to deny Randolph's request to reflect an updated number of access lines and projected usage in its alternative cost study. Further, the Commission concludes that it is appropriate to deny the CMRS Providers' Objections to Findings of Fact Nos. 11, 12, and 28.

<u>FINDING OF FACT NO. 17 (ISSUE NOS. 18 AND 19 – MATRIX ISSUE NOS. 24 AND 24A):</u>

[1] Per Randolph's April 23, 2008 Revised Spreadsheet 2.

[2] Randolph's April 23, 2008 Revised Spreadsheet 2 reflects the updated projected interstate access minutes and projected lines as proposed by Randolph. Based on this Order, those figures are not to be updated, and therefore, the rate of $0.01362 will decrease after Randolph includes the original number of access lines and projected usage.

[3] See specifically, (1) Ellerbe/Sprint PCS – Docket No. P-21, Sub 72, reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (2) Ellerbe/SunCom – Docket No. P-21, Sub 73, adopted Ellerbe's interconnection agreement with Verizon Wireless (See Docket No. P-21, Sub 70), reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (3) MebTel/Sprint PCS – Docket No. P-35, Sub 109, reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (4) MebTel/SunCom – Docket No. P-35, Sub 111, adopted MebTel's interconnection agreement with Sprint PCS (See Docket No. P-35, Sub 109), reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (5) Randolph/Sprint PCS – Docket No. P-61, Sub 96, reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (6) Randolph/SunCom – Docket No. P-61, Sub 97, adopted Randolph's interconnection agreement with Verizon Wireless (See Docket No. P-61, Sub 93), reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (7) Pineville Telephone Company/Alltel Communications, Inc. – Docket No. P-120, Sub 22, reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (8) Pineville Telephone Company/New Cingular Wireless PCS, LLC – Docket No. P-120, Sub 20, reciprocal compensation rate of **<u>$0.015 per MOU</u>**; (9) Saluda Mountain Telephone Company/Alltel Communications, Inc. – Docket No. P-76, Sub 57, reciprocal compensation rate of **<u>$0.015 per MOU</u>**; and (10) Saluda Mountain Telephone Company/New Cingular Wireless PCS, LLC – Docket No. P-76, Sub 55, reciprocal compensation rate of **<u>$0.015 per MOU</u>**.

<u>ISSUE NO. 18 – MATRIX ISSUE NO. 24</u>: Did Randolph's study assume that 70 percent of Randolph's switching costs were usage-sensitive, and if so, was that appropriate?

<u>ISSUE NO. 19 – MATRIX ISSUE NO. 24A</u>: If not appropriate, what percentage of total switching annual costs should be recovered by Randolph's transport and termination rate?

INITIAL COMMISSION DECISION

The Commission concluded that it was appropriate to request Randolph and the CMRS Providers to review Randolph's CPRs to attempt to obtain agreement on the appropriate Randolph-specific usage sensitive switching costs to be included in Randolph's alternative cost study. Since the Commission concluded in Finding of Fact No. 23 that it was appropriate for Ellerbe to adopt Randolph's alternative cost study, Ellerbe should adopt the usage sensitive switching costs agreed to by the Parties for Randolph as a surrogate for Ellerbe's usage sensitive switching costs.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel did not object to this Finding of Fact.

RANDOLPH: Randolph did not object to this Finding of Fact, but provided an update of the required negotiations for Finding of Fact No. 17. Randolph noted that, to facilitate the negotiations, it populated an Excel spreadsheet with all of the data in Randolph's CPRs and undertook to classify each expense into a specific category. Randolph stated that this spreadsheet was provided to the CMRS Providers, who reviewed it and posed written questions to Randolph. Randolph noted that it responded to those questions and, with its responses, it also provided a revised analysis of its COE. Randolph stated that the parties held two conference calls to discuss the analysis of Randolph's COE information and associated issues and that, despite these efforts, the parties had not been able to agree on the appropriate Randolph-specific usage sensitive switching cost to be included in Randolph's alternative cost study. Randolph noted that it has also proposed that the parties involve the Public Staff in their discussions in an effort to reach agreement, but the CMRS Providers declined this suggestion.

Randolph provided two confidential spreadsheets with its Objections and Report on Joint Review of Randolph's CPRs: (1) Randolph Confidential Spreadsheet 1, which reflects Randolph's analysis of its COE that classifies, by category, the investment associated with each feature and functionality in Randolph's switch and (2) Randolph Confidential Spreadsheet 2, which reflects the impact on Randolph's alternative cost study of applying the updated NECA formulae and Randolph's updated access line and usage information[1].

Randolph maintained that, as shown in the COE analysis spreadsheet, 52.6 percent of Randolph's switch investment expense is usage sensitive. Randolph noted that, in doing this analysis, it allocated mixed-use equipment (switch features and functionalities used to support both line-side and trunk-side trunking) based on the total number of trunks, as shown on

[1] On April 23, 2008, Randolph filed a revised copy of Confidential Spreadsheet 2 after it discovered that it made a transposition error in creating the original spreadsheet.

Lines 500 and 501 of that spreadsheet. Randolph stated that the analysis shows that 52.6 percent of Randolph's switch investment was for processor and memory equipment, switch network and related equipment (getting started costs), and trunk side port equipment.

Randolph noted that the second attachment shows Randolph's updated calculation of its transport and termination costs that reflects the NECA average schedule formulae adopted for the one-year period beginning on July 1, 2007 and the most current LSS formulae and includes updated data on access lines and projected minutes of use. Randolph maintained that the updated result is a cost per minute of $0.01767[1] which, when adjusted by the 52.6 percent usage sensitive factor calculated in Randolph's spreadsheet, yields a revised per minute cost for transport and termination for Randolph of $0.01376[2]. Randolph submitted that the calculation of this cost complies with the *RAO*.

Randolph stated that it understands that the CMRS Providers may limit their Objection to this analysis of Randolph's COE to challenging the inclusion of software upgrade costs in the calculation of its usage sensitive switch investment. Randolph argued that the cost of software upgrades is properly included in the development of its usage sensitive switch investment. Randolph noted that these upgrades are necessary to fix bugs in prior software releases; to add functionalities required by the FCC, such as LNP, CALEA, intraLATA presubscription, and interchangeable NPA/NXX codes; and to otherwise update the switch software to keep Randolph's switch functional and subject to support by Nortel, its switch supplier.

Randolph asserted that its investment in software upgrades for its switch should be included in the determination of Randolph's usage sensitive switching investment. Randolph noted that, in upholding the establishment of switching rates in a TELRIC proceeding before the New York Public Service Commission (PSC), the FCC explicitly rejected the argument that TELRIC does not permit recovery of the cost of augmented switches, which are existing switches with capacity upgrades, and that Bell Atlantic's proposal to recover such costs violated TELRIC. Randolph stated that the D.C. Circuit agreed with the FCC, noting that it was comfortable deferring to the FCC's conclusion that the New York PSC had not made such clear errors that the resulting switching costs, which included the cost of such upgrades, fell outside of the range that a reasonable application of TELRIC principles would produce. Randolph maintained that the Court noted that FCC counsel explained that growth additions to existing switches cost more than new switches only because vendors offer substantial new switch discounts in order to make telephone companies dependent on the vendors' technology for switch updates. Randolph noted that, based on this fact, the Court found that the FCC reasonably concluded that inclusion of growth additions did not violate TELRIC.

Randolph stated that the situation a company like Randolph faces is that it has a single switch and is dependent on its switch vendor's technology to accomplish switch upgrades required by the FCC. Randolph argued that the investments made in those upgrades are a legitimate part of Randolph's usage sensitive switch investment and do not relate to line ports.

[1] Revised by the April 23, 2008 filing to $0.01753.

[2] Revised by the April 23, 2008 filing to $0.01362. The original spreadsheet reported a figure of $0.01767 in error.

Randolph noted that inclusion of Randolph's software upgrade investments is also consistent with the Commission's *BellSouth UNE Order*, which was a proceeding governed by the FCC's TELRIC rules (which do not control in this proceeding). Randolph maintained that AT&T/WorldCom challenged BellSouth's calculation of its switching investment for purposes of establishing UNE prices because it included switch upgrade costs. Randolph stated that the *BellSouth UNE Order* is the basis for the Public Staff's position in the present dockets that the usage sensitive getting started cost of a switch is the entire switch investment, except for the line port investment. Randolph asserted that, if a consistent approach is followed here, then Randolph's software upgrade costs will be included in the determination of the Company's usage sensitive switch investment.

Randolph stated that, in the BellSouth UNE docket, there were issues concerning whether BellSouth had appropriately assigned switch investment outputs from its cost model for the getting started investment and the equivalent POTs half calls (EPHC) investment to the minutes of use and feature elements. Randolph asserted that these issues included questions as to the appropriateness of BellSouth's assignment of costs for switch equipment that it considered to be either new, replacement or growth, and that equipment purchased to service additional demand is considered growth.

Randolph noted that AT&T/WorldCom argued that the getting started costs and all EPHC investment should be assigned to the ports, but the Commission rejected those arguments. Randolph noted that the Commission approved BellSouth's allocation of the getting started and EPHC investment, which are the costs for common equipment in the switch module. Randolph argued that, consistent with the *BellSouth UNE Order*, Randolph's usage sensitive switch costs include its investment in switch software upgrades.

Randolph maintained that, given the breadth of the definition of getting started investment and the findings in the *BellSouth UNE Order*, it appears that the Commission concluded that all switch investment except line ports is usage sensitive. Randolph noted that application of the logic of the Commission's decision in the BellSouth UNE docket to the present case would mean that Randolph's switch software upgrades are properly considered a part of its usage sensitive switch investment.

Randolph requested that the Commission approve a reciprocal compensation rate of \$0.01376[1] per minute for Randolph.

CMRS PROVIDERS: The CMRS Providers noted that the *RAO* requires Randolph to analyze its CPRs so that the parties may calculate a company-specific, usage-sensitive percentage of switching investment and costs, rather than simply adopting the 70 percent assumption inherent in the NECA average schedule formulae. The CMRS Providers noted that Randolph has performed this analysis, and that the results are attached as Exhibit 1 to Randolph's Objections. The CMRS Providers stated that Randolph determined that 52.6 percent of its embedded switch investment is attributable to equipment considered to be usage-sensitive as defined by the *RAO*. The CMRS Providers maintained that, notably, 24.4 percent (almost half) of the 52.6 percent

[1] Revised in the April 23, 2008 filing to \$0.01362.

represents investment in switch software upgrades Randolph has made over the years to maintain the currency of its switch functionality or to enable new switch functions.

The CMRS Providers noted that Randolph argued that its investments in switch software upgrades are usage-sensitive. The CMRS Providers contended that investments in switch software upgrades are not usage-sensitive and, therefore, should not be included in switching costs for the purpose of establishing a transport and termination rate; thus, the issue is whether to use 52.6 or 28.2 percent to re-run Randolph's cost study as required by the *RAO* (28.2 percent = 52.6 percent - 24.4 percent).

The CMRS Providers asserted that the Act allows Randolph's rate to recover the "additional costs"[1] of the "transport and termination"[2] of wireless traffic. The CMRS Providers further stated that the FCC has interpreted the "additional cost" standard as limiting recovery to usage-sensitive costs.[3] The CMRS Providers noted the Commission has confirmed that the Guidelines in the *Modification Order* require that Randolph's switching costs recovered in the transport and termination rate be limited to usage-sensitive costs.

The CMRS Providers asserted that Randolph's switch software upgrade investments were lump-sum amounts, as shown on Exhibit 1, and did not vary by usage. The CMRS Providers maintained that this means software upgrade investments are not usage-sensitive; the cost of upgrades remains the same regardless of the number of calls processed.

The CMRS Providers stated that it also should be noted, as witness Conwell pointed out in his direct testimony, that the FCC Common Carrier Bureau in the *Virginia Arbitration Cost Order* found that software right-to-use fees are not usage-sensitive.[4] The CMRS Providers further stated that, in the FCC's *USF Inputs Order*, the FCC concluded that software upgrade costs should be excluded altogether from the current cost of purchasing and installing new switches or the forward-looking cost of switching.[5] The CMRS Providers argued that, therefore, federal law requires that the usage-sensitive portion of Randolph's switching investments and costs be set at 28.2 percent.

The CMRS Providers stated that, in summary, Randolph's proposed switching cost is $0.0042 per minute, after adjusting its cost study to reflect current NECA and LSS formulae and 52.6 percent usage-sensitive switching costs. The CMRS Providers recommended two modifications to better reflect forward-looking switch costs and more efficient utilization; those modifications lower Randolph's switching cost to $0.0031 per minute. The CMRS Providers stated that they also believe that an additional adjustment should be made to remove

[1] Section 252(d)(2)(A)(ii).

[2] Section 252(d)(2)(A)(i).

[3] *First Report and Order*, Paragraph 1057.

[4] Conwell Direct, page 38.

[5] *10th Report and Order*, Paragraph 315: "We believe that this restriction will eliminate switches whose book values contain a significant amount of upgrade costs, and recognizes that, when ordering new switches, carriers typically order equipment designed to meet short-run demand."

software upgrade investments from the usage-sensitive percentage. The CMRS Providers stated that such an adjustment is likely to reduce Randolph's switching cost from $0.0031 per minute to a level below witness Conwell's estimate of $0.0023 per minute. The CMRS Providers stated that they are not asking that Randolph's switching costs be set below $0.0023 per minute. The CMRS Providers maintained that, however, Randolph's transport and termination rate should include *no more* than $0.0023 per minute for switching.

NON-PARTY COMMENTS

EMBARQ: Embarq did not comment on this Finding of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not comment on this Finding of Fact.

VERIZON WIRELESS: Verizon Wireless did not comment on this Finding of Fact.

INITIAL COMMENTS

RLECs: The RLECs noted that the CMRS Providers challenged Randolph's determination that 52.6 percent of its switch investment is usage sensitive. The RLECs stated that the CMRS Providers, as they sought modifications to the *RAO* to further understate MebTel's switching cost, again argue here that the Commission should not take Randolph's investment in switch software upgrades into account in determining the extent of its switch investment.

The RLECs maintained that, in proceedings to establish UNE rates for the largest ILECs under TELRIC in Docket P-100, Sub 133d, the Commission has allowed even ILECs as large as BellSouth to recover their "getting started" switch costs. The RLECs noted that even witness Conwell acknowledged this fact; witness Conwell defined "getting started" cost as the "switch processor, switch network and related equipment," and he acknowledged that these costs have traditionally been considered to be usage sensitive. The RLECs stated that the Commission's Order setting BellSouth's UNE pricing, which the Commission took notice of in this docket on motion of the Public Staff, indicates that the usage sensitive "getting started" cost of a switch is the entire cost of the switch, except for the line port investment.

The RLECs stated that the CMRS Providers acknowledged that the switch software upgrades have been made by Randolph "over the years to maintain the currency of its switch functionality or to enable new switch functions." The RLECs asserted that, as this acknowledgement recognizes, the switch software upgrades are costs incurred to either insure continued smooth operation of Randolph's switch or to comply with FCC mandates requiring implementation of additional switch functionalities. The RLECs argued that the costs of keeping switching software updated are part of the cost of maintaining the switch processor and keeping it compliant with the FCC's requirements, and thus the cost of a software upgrade is effectively a "continuing getting started cost" of the type the Commission has previously allowed other large ILECs to recover in establishing UNE prices.

CMRS PROVIDERS: The CMRS Providers noted that Randolph performed the analysis of its CPRs and filed the results in its "Report on Joint Review of Randolph's Continuing Property Records" in conjunction with its Objections. The CMRS Providers stated that, in its Report, Randolph claims that 52.6 percent of its embedded switch investment is attributable to equipment considered to be usage-sensitive as defined by the *RAO*. The CMRS Providers asserted that, notably, 24.4 percent of the 52.6 percent represents investment in switch software upgrades that Randolph has made over the years to maintain the currency of its switch functionality or to enable new switch functions, as can be determined by an analysis of Randolph's Confidential Spreadsheet 1 attached to the Report.

The CMRS Providers contended that, however, the investments in switch software upgrades are not usage-sensitive and therefore should not be included in determining switching costs for the purpose of establishing a transport and termination rate. The CMRS Providers maintained that, for this reason, the issue is whether to use 52.6 percent or 28.2 percent to re-run Randolph's alternative cost study as required by the *RAO*.

The CMRS Providers noted that Randolph's Objections and Report do not define or discuss what additional cost and usage sensitive mean. The CMRS Providers noted that, according to the FCC:

> [T]he 'additional cost' to the LEC of terminating a call that originates on a competing carrier's network primarily consists of the traffic-sensitive component of local switching. The network elements involved with the termination of traffic include the end-office switch and local loop. The costs of local loops and line ports associated with local switches do not vary in proportion to the number of calls terminated over these facilities. We conclude that such non-traffic sensitive costs should not be considered additional costs when a LEC terminates a call that originated on the network of a competing carrier.[1]

The CMRS Providers argued that costs that remain constant regardless of the number of calls terminated are neither additional costs nor usage-sensitive and therefore cannot be recovered through transport and termination rates.

The CMRS Providers asserted that the definition makes clear that switch upgrade costs are not usage-sensitive. The CMRS Providers further stated that the costs of providing number portability are the same whether a switch processes one hundred thousand minutes of use per year, or one million. The CMRS Providers maintained that the same is true for upgrades to provide intraLATA presubscription, interchangeable NPA/NXX codes, and CALEA compliance. The CMRS Providers stated that this point is demonstrated by Randolph Confidential Spreadsheet 1. The CMRS Providers argued that Randolph's switch software upgrade investments were all lump-sum amounts and did not vary by usage. The CMRS Providers stated that the cost of upgrades, in other words, was the same regardless of the number of calls processed. The CMRS Providers opined that Randolph is certainly entitled to recover these switch upgrades costs, but not through transport and termination rates charged to the CMRS Providers.

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[1] *First Report and Order* at Paragraph 1057.

The CMRS Providers noted that the FCC Common Carrier Bureau in the *Virginia Arbitration Cost Order* issued in 2003 has specifically held that software right-to-use fees should be recovered on a per port basis rather than a per line or usage basis. The CMRS Providers maintained that, likewise, the FCC has ruled that software upgrade costs should be excluded altogether from the current cost to purchase and install new switches, or the forward-looking cost of switching. The CMRS Providers noted that the FCC stated in the *USF Inputs Order* as follows:

> We believe that this restriction will eliminate switches whose book values contain a significant amount of upgrade costs, and recognizes that, when ordering new switches, carriers typically order equipment designed to meet short-run demand. (Paragraph 315)
>
> Switches, augmented by upgrades, may provide carriers the ability to provide supported services, but do so at greater costs. Therefore, such augmented switches do not constitute cost-effective forward-looking technology. (Paragraph 317)

The CMRS Providers maintained that Randolph, in support of its claim that switch upgrade costs should be recovered through transport and termination rates, cites a decision from the United States District Court of Appeals for the D.C. Circuit, upholding a ruling of the New York PSC recommending that Section 271 relief be granted to Bell Atlantic. The CMRS Providers stated that it is ironic that Randolph would cite this federal decision because it does not actually stand for the proposition stated; the FCC's TELRIC methodology was not applied in that proceeding.

The CMRS Providers asserted that the New York case involved whether Bell Atlantic was entitled, under Section 271 of the Act, to be granted authority to provide long distance service. The CMRS Providers noted that one issue in that determination was whether Bell Atlantic's UNE rates, including local switching, were appropriate. The CMRS Providers stated that the D.C. Circuit expressly pointed out that the federal standard applicable to such a determination did not include the use of TELRIC pricing which is the appropriate standard in this proceeding. The CMRS Providers argued that, thus, whether or not switch upgrade costs were recoverable under TELRIC was not decided by the cited case. The CMRS Providers maintained that, under the federal law cited, as well as the cost study Guidelines adopted by the Commission, switch upgrade costs are not properly included in transport and termination rates. The CMRS Providers opined that the usage-sensitive portion of Randolph's switching costs should therefore be set at 28.2 percent.

ALLIANCE: The Alliance did not address this Finding of Fact in its initial comments.

EMBARQ: Embarq did not address this Finding of Fact in its initial comments.

PUBLIC STAFF: The Public Staff noted that Randolph, in its Report on the status of the parties' efforts to jointly review Randolph's CPRs, stated that it is unable to report that the parties have come to agreement on the appropriate Randolph-specific usage sensitive switching cost to be used in Randolph's cost study. The Public Staff maintained that Randolph also noted that it proposed to involve the Public Staff in the negotiation discussions, but that the CMRS Providers declined this suggestion.

The Public Staff stated that Randolph maintained that its CPRs support a traffic-sensitive factor of 52.6 percent and attached a spreadsheet analyzing its switch plant account. The Public Staff asserted that, based on a review of this spreadsheet, it believes that Randolph's proposed factor is reasonable. The Public Staff noted that it is less than the default 70 percent factor used by the FCC for rural companies and is close to the factor found by analyzing MebTel's Mebane DCO switch. The Public Staff recommended that the Commission modify its finding to indicate that Randolph's CPRs support a traffic-sensitive factor of 52.6 percent and that this factor is appropriate for use in Randolph's alternative cost study.

REPLY COMMENTS

RLECs: The RLECs stated that the principal focus of the CMRS Providers' initial comments as to Randolph's objection concern the CPR review and their opposition to the inclusion of switch software upgrade investments in calculating Randolph's switch investment. The RLECs maintained that the CMRS Providers argued that these investments are not usage-sensitive as defined by the FCC and thus are not properly included. The RLECs argued that the foundation of this argument is the CMRS Providers' depiction of the *RAO* as having directed the review of Randolph's CPRs so that the parties might calculate a company-specific, usage-sensitive percentage of switching investment and costs consistent with federal law, rather than simply adopting the 70 percent assumption inherent in the NECA average schedule formulae.

The RLECs noted that, as a threshold consideration, it is clear from the Commission's *Modification Order* that Randolph's cost study, and the determination of its switch investment, does not have to be consistent with the FCC's TELRIC requirements. The RLECs stated that a second important consideration is the concession by the CMRS Providers that this dispute involves investment in switch software upgrades Randolph has made over the years to maintain the currency of its switch functionality or to enable new switch functions in accordance with FCC requirements. The RLECs maintained that there is thus no question that the switch software upgrade investments were made to either keep Randolph's switch functional and eligible for support by the switch vendor, or to comply with the FCC's directives requiring the addition of switch functionalities such as local number portability, CALEA, etc.

The RLECs asserted that the CMRS Providers' argument in favor of excluding these legitimate investments in Randolph's switching costs is based on Section 252(d)(2)(A) of the Act. The RLECs maintained that this is effectively a rehash of the CMRS Providers' arguments that either the Commission's alternative cost study guidelines are effectively the same as the FCC's TELRIC requirements or that the Commission was not able, under Section 251(f)(2), to excuse the RLECs from complying with the FCC's TELRIC requirements. The RLECs noted that they addressed these arguments at length in their initial comments and, for the reasons set forth in their initial comments, in the Public Staff's initial comments, and in the *RAO*, these CMRS Provider arguments are without merit.

The RLECs noted that the CMRS Providers argue for exclusion of Randolph's investment in switch software upgrades premised on the FCC's interpretation of the TELRIC pricing concept of additional costs as limiting an ILEC's recovery to only usage sensitive costs. The RLECs stated that the CMRS Providers rely on Paragraph 1057 of the FCC's *First Report and Order* in support of their argument. The RLECs argued that that Order does not support the CMRS Providers' argument regarding exclusion of switch software investment for two reasons. The RLECs stated that, first, the language that the CMRS Providers quote from the *First Report and Order* clearly provides that local loops and line ports associated with local switches do not vary in proportion to the number of calls terminated. The RLECs stated that Randolph has not sought to recover, and the *RAO* does not provide for RLEC recovery of, costs for local loops or line ports. The RLECs maintained that, however, nothing in the language of Paragraph 1057 suggests that switch software is to be excluded from the additional cost determination. The RLECs stated that the CMRS Providers seek to lump switch software in with loops and line ports without any basis for doing so.

Second, the RLECs stated, the FCC pointed out in the *First Report and Order* that certain aspects of the Act and FCC regulations, including TELRIC pricing rules, do not apply to a rural telephone company until its rural exemption has been termination. The RLECs noted that they are all rural telephone companies as defined in Section 153(37) of the Act and that the Commission has not terminated the Section 251(f)(1) rural exemptions of Ellerbe, MebTel, or Randolph. The RLECs maintained that, in addressing various provisions of the Act and its regulations, including its TELRIC rules, the FCC likewise repeatedly states that certain small ILECs are not subject to the FCC's rules under Section 251(f)(1) of the Act, unless otherwise determined by a state commission, and that these small ILECs may seek relief from the FCC's rules from the relevant state commission pursuant to Section 251(f)(2). The RLECs noted that this is precisely what the RLECs did in Docket No. P-100, Sub 159; they sought relief from the application of the FCC's TELRIC rules under Section 251(f)(2) and that relief was granted by the Commission, as provided for by the Act and as contemplated by the FCC.

The RLECs noted that this argument is really just another chapter in the book that the CMRS Providers continue to try to write about their views about the significance (or insignificance) of the Commission's *Modification Order*. The RLECs asserted that the simple fact is that, in Docket No. P-100, Sub 159, the Commission excused the RLECs from having to provide TELRIC-compliant cost studies, which unavoidably means that they were excused from having their reciprocal compensation determined based on TELRIC. The RLECs noted that the Commission has heard this argument multiple times, analyzed it, and rejected it in the *RAO*.

The RLECs noted that the Public Staff, in its initial comments, concluded that the 52.6 percent usage-sensitive percentage reflected in the RLECs' spreadsheets is reasonable. The RLECs stated that the Public Staff is the author of the alternative cost study guidelines which the Commission adopted in the *Modification Order*. The RLECs argued that, thus, there is added significance to the Public Staff's statement supporting the inclusion of Randolph's usage-sensitive switch investment. The RLECs agreed with the Public Staff and endorsed the Public Staff's recommendation to the Commission on this point.

The RLECs further stated that the Public Staff's position that Randolph's switch investment is usage-sensitive is consistent with prior rulings by the Commission. The RLECs noted that the Commission's Order setting BellSouth's UNE rates in Docket No. P-100, Sub 133d, which the Commission formally noticed in this docket on motion of the Public Staff, indicates that the usage-sensitive getting started cost of a switch is the entire cost of the switch, except for the line port investment. The RLECs maintained that CMRS Providers witness Conwell defined getting started costs as the switch processor, memory, switch network, and related equipment, and that he acknowledged that these costs have traditionally been considered to be usage sensitive. The RLECs asserted that, under either the standard that the Commission applied in Docket No. P-100, Sub 133d, or under the traditional standard acknowledged by witness Conwell, Randolph's investment in software upgrades for its switch amount to continuing investment in those aspects of the switch (switch processor, memory, switch network, and related equipment) which constitute the getting started costs of the switch.

The RLECs stated that the CMRS Providers acknowledge that Randolph has invested in switch software upgrades over the years to maintain the currency of its switch functionality or to enable new switch functions. The RLECs noted that, as this acknowledgement recognizes, the switch software upgrades are costs incurred to either insure continued smooth operation of Randolph's switch or to comply with FCC mandates requiring implementation of additional switch functionalities. The RLECs maintained that the costs of keeping software updated are part of the cost of maintaining the switch processor and keeping it compliant with the FCC's requirements, and, thus, the investment in a software upgrade is effectively a continuing getting started cost of the type the Commission has previously allowed other large ILECs to recover in establishing UNE prices. The RLECs argued that the CMRS Providers receive the benefit of Randolph having kept its switch software current, thus maintaining the overall life of the switch, and these investments are properly included in determining Randolph's total switch investment.

The RLECs noted that the CMRS Providers argued that the costs of FCC-mandated software upgrades for number portability, intraLATA presubscription, and CALEA are the same regardless of volumes processed by the switch. The RLECs further stated that the CMRS Providers argued that the fixed dollar amounts for these investments shown on Randolph's CPRs demonstrates that these amounts were priced on a fixed basis. The RLECs argued that there is nothing in the CPRs showing how those dollar amounts were arrived at and the degree to which they were determined based on fixed or usage based pricing algorithms. The RLECs asserted that the fact that Randolph paid the switch manufacturer a certain dollar amount does not demonstrate that the amount was determined on a lump-sum, fixed basis.

The RLECs noted that the CMRS Providers also cited to the FCC Common Carrier Bureau's conclusion in the *Virginia Arbitration Cost Order* as evidencing the FCC's position on right-to-use fees. The RLECs asserted that the CMRS Providers neglect to mention that this conclusion was based specifically on Verizon's statement in that docket that it pays such fees primarily on a per switch basis and not on a usage basis; evidence of how software upgrade fees are developed for Randolph is not part of the record in this case.

The RLECs noted that the CMRS Providers also again rely on the FCC's *USF Inputs Order* in asking the Commission to ignore Randolph's switch software upgrade investments.

The RLECs stated that this time they offer a quote from the *USF Inputs Order* relating to the FCC's decision to not utilize data on switches more than three years old because the FCC recognized that such switches would contain a significant amount of upgrade costs. The RLECs asserted that, as the Commission well knows by now, the FCC's *USF Inputs Order* is not dispositive of this issue for two reasons. First, the RLECs noted, that data was gathered for use in determining universal service support for non-rural LECs, not for establishing reciprocal compensation for rural ILECs (or ILECs of any size for that matter). The RLECs noted that the vast majority of the data and the policy focus reflected in the *USF Inputs Order* relates to non-rural ILECs. The RLECs stated that, second, the *USF Inputs Order* was not directed toward the application of the FCC's TELRIC principles in the context of establishing reciprocal compensation. The RLECs stated that the CMRS Providers' reliance on the *USF Inputs Order* continues to be inappropriate, as the FCC specifically cautioned against using the inputs developed for USF in other proceedings – which is just what the CMRS Providers are trying to do in this case. The RLECs noted, specifically, that the FCC stated in Paragraph 32 of the *USF Inputs Order*:

> . . . [T]he Commission has not considered what type of input values, company-specific or nationwide, nor what specific input values, would be appropriate for any other purposes. The federal cost model was developed for the purpose of determining federal universal service support, and it may not be appropriate to use nationwide values for other purposes, such as determining prices for unbundled network elements. We caution parties from making any claims in other proceedings based upon the input values we adopt in this Order.

The RLECs maintained that it is abundantly clear from the *RAO* that the Commission considered the CMRS Providers' arguments urging the Commission to use data from the *USF Inputs Order*. The RLECs asserted that the Commission, having considered the CMRS Providers' arguments, rejected them. The RLECs argued that the *USF Inputs Order* had nothing to do with determining reciprocal compensation. Further, the RLECs asserted that, just as that Order was not an appropriate source of data for use in determining the RLECs' switch investment for purposes of establishing reciprocal compensation, the methodology utilized by the FCC in gathering data for determining USF support for non-rural ILECs, and the FCC's decision to disregard cost data on switches more than three years old, was not necessarily relevant to the question of the propriety of including switch software upgrades in determining an RLEC's switch investment for the purpose of establishing transport and termination costs. The RLECs noted that, simply put, the *USF Inputs Order* is not, as represented by the CMRS Providers, federal law prohibiting consideration of Randolph's switch software investments.

The RLECs further noted that the CMRS Providers, in their initial comments, seek to dismiss the D.C. Circuit's decision in *AT&T Corp. v. FCC,* 220 F.3d 607 (DC Cir. 2000), a case cited in Randolph's Objections. The RLECs stated that Randolph cited that case because it demonstrates that, even in a proceeding involving the application of TELRIC principles, the FCC has allowed an ILEC to recover switch upgrade costs. The RLECs maintained that, even though the Commission is not applying the FCC's TELRIC rules to the RLECs in the instant proceeding, *AT&T Corp. v. FCC* directly refutes the CMRS Providers' argument that switch upgrade costs could never be recovered under the FCC's TELRIC rules.

The RLECs asserted that, in that case, AT&T (then a CLEC) and other CLECs challenged the FCC's approval of the New York PSC's decision to support Bell Atlantic's Section 271 application for interLATA authority. The RLECs noted that, as part of that process, the New York PSC had reviewed Bell Atlantic's compliance with the fourteen point competitive checklist which had to be satisfied in order for an RBOC to obtain interLATA authority.

The RLECs stated that AT&T appealed the FCC's ruling granting Bell Atlantic's application, and the D.C. Circuit affirmed the FCC's decision. The RLECs maintained that the CMRS Providers, in their initial comments, attempt to distinguish this case by stating that the FCC's TELRIC methodology was not applied in that proceeding. The RLECs asserted that that is simply not true. The RLECs stated that before the FCC, AT&T challenged the appropriateness of Bell Atlantic's UNE rates, specifically challenging the inclusion of augmented switch investment under TELRIC pricing principles. The RLECs stated that TELRIC principles were the primary benchmark the FCC applied in making that determination.

The RLECs stated that the FCC's Order, which the D.C. Circuit affirmed, specifically considered the question of including augmented switch investment in developing UNE rates under TELRIC pricing principles. The RLECs maintained that the FCC specifically agreed with the New York PSC that it had appropriately exercised its flexibility to set prices to produce rates that were consistent with TELRIC principles. The RLECs asserted that it is quite clear from the D.C. Circuit's Opinion that *AT&T Corp. v. FCC* involved the application of TELRIC principles. The RLECs maintained that the D.C. Circuit reviewed the history of the FCC's development of TELRIC and then expressly noted that it was reviewing the FCC's TELRIC compliance determinations. The RLECs noted that the Court then stated:

> AT&T mounts four challenges to the FCC's approval of Bell Atlantic's applications, the first two of which Covad joins: (1) Bell Atlantic's prices for certain network elements do not conform to the TELRIC pricing methodology . . .
>
> * * *
>
> AT&T and Covad claim that the rates the NYPSC set for switches – the equipment used to direct calls to their destination – . . . erroneously include the cost not just of new switches, but of more costly 'growth additions' to existing switches. With respect to the latter argument, appellants claim that because TELRIC contemplates construction of a new network using the most efficient technology, it requires the NYPSC to have used the less costly new switches as the basis for the rates.

The RLECs stated that the D.C. Circuit affirmed the FCC's decision, ruling that the FCC reasonably concluded that the inclusion of switch addition costs did not violate TELRIC. The RLECs maintained that, thus, there can be no serious question that *AT&T Corp. v. FCC* did involve the application of TELRIC. The RLECs asserted that, likewise, there can be no serious question that the New York PSC, the FCC, and the D.C. Circuit all found that the inclusion of switch upgrade costs in the development of Bell Atlantic's UNE price did not violate TELRIC.

The RLECs noted that, even though the Commission is not applying TELRIC here, this result is not surprising. The RLECs stated that, first, the Court specifically recognized that switch vendors offer switch discounts to an RBOC like Bell Atlantic in order to make telephone companies dependent on the vendor's technology for updating the switches. The RLECs maintained that, second, the Court also recognized that, as the FCC had before it, TELRIC is not a rigid formula and that it affords state commissions significant latitude. The RLECs provided the following quote from the Court's decision:

> TELRIC is not a specific formula, but a framework of principles that govern the pricing determinations. [W]hile TELRIC consists of 'methodological principles' for setting prices, states retain flexibility to consider 'local technological, environmental, regulatory, and economic conditions.' Bell Atlantic 15 F.C.C.R. at 4084 ¶ 244 (quoting *Local Competition First Report and Order*, 11 F.C.C.R. at 15812).

The RLECs argued that, by continuing to present their arguments about what they contend TELRIC would require, the CMRS Providers apparently hope to avoid the reality that the *Modification Order* effectively excused the RLECs from complying with TELRIC and Section 252(d). The RLECs stated that, as part of this approach, the CMRS Providers cite three cases which they depict as showing the rigidity of TELRIC's requirements: *Verizon Communications v. FCC*, 535 U.S. 467, 122 S. Ct. 1646, 152 L.Ed.2d 701 (2002); *Mpower Communications v. Illinois Bell*, 457 F.3d 625 (7th Cir. 2006); and *AT&T Communications of Illinois v. Illinois Bell*, 349 F.3d 402 (7th Cir. 2003). The RLECs noted that all three of these cases involve the application of TELRIC to a RBOC.

The RLECs asserted that, while *Verizon* speaks to using forward looking cost data, the 7th Circuit decisions in *Mpower* and *AT&T* both cite the D.C. Circuit's decision in *AT&T Corp. v. FCC, supra*, and go on to amplify the relative flexibility afforded state commissions, even when they are applying TELRIC. The RLECs maintained that, in fact, immediately following the "out the window" language that the CMRS Providers quoted from *AT&T Communications of Illinois* on page 10 of their initial comments, the 7th Circuit went on to say that TELRIC is a framework rather than a formula and that there is "considerable play in the joints". The RLECs noted that later, building on *AT&T Corp. v. FCC, supra*, the 7th Circuit recognized that:

> The 1996 Act is itself technologically creaky: the assumptions of a decade ago no longer describe the state of competition in this business, and with the advent of competition from so many sources the whole regulatory model – which assumes that each ILEC retains a natural monopoly on cabling and switches – is open to question. [Mpower, 457 F.3d at 628]

The RLECs argued that TELRIC does not address every consideration for a state agency to consider and that a good deal of discretion is left to the states.

The RLECs stated that the cases now relied on by the CMRS Providers concerning the application of TELRIC requirements under Section 252(d) are not relevant here, because of the *Modification Order* and the fact that the Commission has excused the RLECs from complying with TELRIC. The RLECs stated that the Commission should conclude, as recommended by the Public Staff, that Randolph's investments in switch software upgrades are properly included in the development of Randolph's cost of providing transport and termination of CMRS-originated traffic.

CMRS PROVIDERS: The CMRS Providers did not specifically address this issue in their reply comments.

ALLIANCE: The Alliance did not file reply comments.

EMBARQ: Embarq did not address this issue in its reply comments.

PUBLIC STAFF: The Public Staff did not file reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth did not address this issue in their reply comments.

VERIZON WIRELESS: Verizon Wireless did not address this issue in its reply comments.

DISCUSSION

No party filed an Objection to Finding of Fact No. 17; however, the Parties informed the Commission that they were unable to fulfill the directives in the *RAO* to mutually agree on an appropriate usage sensitive switching cost to be reflected by Randolph in its alternative cost study. Randolph filed a copy of a spreadsheet which analyzes its CPRs and recommended that the Commission find that 52.6 percent[1] of Randolph's switching costs are usage sensitive, a figure which includes 24.4 percent for software upgrades. The Public Staff supported Randolph's proposed factor. The CMRS Providers objected to Randolph reflecting 24.4 percent for software upgrades in its calculated usage sensitive factor and, instead, proposed that the Commission find that 28.2 percent[2] of Randolph's switching costs are usage sensitive.

The Commission agrees with Randolph that the RLECs, in Docket No. P-100, Sub 159, sought relief from the application of the FCC's TELRIC rules under Section 251(f)(2) and that relief was granted by the Commission, as provided for by the Act and as contemplated by the FCC. The Commission also agrees with Randolph that the simple fact is that, in Docket No. P-100, Sub 159, the Commission excused the RLECs from having to provide TELRIC-compliant cost studies, which unavoidably means that they were excused from having their reciprocal compensation rates determined based on TELRIC. The Commission has heard this argument multiple times, analyzed it, and rejected it in the *RAO*. The Commission does not find discussions or arguments concerning TELRIC proceedings determinative in these dockets, since the cost studies to be approved in this proceeding are not required to be TELRIC-complaint and must only adhere to the seven guidelines outlined in the *Modification Order*. Therefore, arguments concerning cases such as the FCC Common Carrier Bureau's *Virginia Arbitration*

[1] This figure includes 9.3 percent for trunk side port equipment; 24.4 percent for processor and memory equipment; and 18.9 percent for switch network and related equipment.

[2] 28.2 percent figure includes 9.3 percent for trunk side port equipment and 18.9 percent for switch network and related equipment. The CMRS Providers proposed to exclude 24.4 percent for software upgrades.

Cost Order are of little guidance in this case, which is governed by the Commission's *Modification Order*.

The Commission further agrees with Randolph that software upgrade costs are part of the cost of maintaining the switch processor and keeping it compliant with the FCC's requirements and that, thus, investment in a software upgrade is effectively a continuing getting started cost of the type the Commission has previously allowed other large ILECs to recover in establishing UNE prices. The Commission also agrees that the CMRS Providers receive the benefit of Randolph having kept its switch software current, thus maintaining the overall life of the switch, and that these investments are properly included in determining Randolph's total switch investment.

The Commission also notes that the CMRS Providers argued in this docket that MebTel's usage-sensitive switching costs should include getting started costs[1]. The Commission agrees with Randolph that software upgrades are essentially continuing getting started costs.

The CMRS Providers pointed out that the FCC's *USF Inputs Order* found that software upgrade costs should be excluded altogether from the current cost to purchase and install new switches. The Commission is particularly persuaded to reject the CMRS Providers argument in this regard by the RLECs' observation that the FCC's *USF Inputs Order* contains a paragraph (Paragraph 32) which specifically cautions parties from making any claims in other proceedings based on the input values the FCC adopted in the *USF Inputs Order*.

The Commission also gives some weight to the RLECs' observation that, since the Public Staff is the author of the alternative cost study guidelines which the Commission adopted in the *Modification Order*, there is added significance to the Public Staff's decision to support the inclusion of Randolph's usage-sensitive switch investment. Further, the RLECs noted that the large ILECs were allowed to recover software upgrade costs in the TELRIC UNE proceeding, and that the CMRS Providers did not refute that assertion. The Commission believes it would be contradictory to allow the large ILECs to recover such costs in their TELRIC-based UNE rates while declining to allow Randolph to recover such costs in its non-TELRIC based reciprocal compensation rates.

Therefore, based on the discussion above, the Commission finds it appropriate to adopt Randolph's proposed usage sensitive switching factor of 52.6 percent for use in Randolph's alternative cost study.

CONCLUSIONS

The Commission concludes that the appropriate usage sensitive switching cost percentage to be included in Randolph's alternative cost study is 52.6 percent.

FINDING OF FACT NO. 23 (ISSUE NO. 25 - MATRIX ISSUE NO. 26): Was it appropriate for Ellerbe to adopt Randolph's cost study?

[1] See page 56 of the *RAO* and page 21 of the CMRS Providers' Proposed Order filed on July 2, 2007.

INITIAL COMMISSION DECISION

The Commission concluded that it was reasonable and appropriate for Ellerbe to adopt Randolph's alternative cost study results with the adjustments therein identified.

MOTIONS FOR RECONSIDERATION

MEBTEL: MebTel did not object to this Finding of Fact and the Commission's resolution of this issue.

RANDOLPH: Randolph did not object to this Finding of Fact and the Commission's resolution of this issue.

CMRS PROVIDERS: The CMRS Providers asserted that the *RAO* gives Ellerbe a "free pass" and completely absolves Ellerbe of the duty to perform a cost study. Further, the CMRS Providers argue that the *RAO* absolves Ellerbe's transport and termination rate from bearing any resemblance whatsoever to Ellerbe's network and costs. According to the CMRS Providers, 47 C.F.R. 505(e) requires that an ILEC's reciprocal compensation rates must be based upon a cost study which is included in the record of any state proceeding in which rates are being established. Additionally, the CMRS Providers argued that the surrogate study that Ellerbe utilized as representative of Ellerbe's network and costs was not representative and appropriate because Randolph did not use its own data to develop the Randolph cost study. For these reasons, the CMRS Providers assert that the *RAO's* ruling on this issue is improper under federal law, the Commission's *Modification Order* in Docket No. P-100, Sub 159 and other rulings included within the *RAO* itself.

NON-PARTY COMMENTS

EMBARQ: Embarq did not comment on this Finding of Fact.

TWTC AND COMPSOUTH: TWTC and CompSouth did not comment on this Finding of Fact.

VERIZON WIRELESS: Verizon Wireless did not comment on this Finding of Fact.

INITIAL COMMENTS

RLECs: According to the RLECs, the CMRS Providers/Alltel object to the provision in the *RAO* granting Ellerbe's request to be allowed to adopt the Randolph cost study. Alltel asserts that no ILEC can ever adopt any other company's cost study. The RLECs point out that Guideline 2 in the *Modification Order* specifically provides that an RLEC can use the cost data that is "a surrogate of the company's cost." Alltel seeks to avoid the reach of this aspect of the *Modification Order* by contending that "nothing in the record indicates that Randolph's study is even remotely representative of Ellerbe's network and costs." According to the RLECs, however, Alltel offered no evidence in the hearing to illustrate that Ellerbe's network was so dissimilar to Randolph's that it was inappropriate for Ellerbe to adopt Randolph's alternative cost study. Furthermore, the record is replete with evidence that Ellerbe lacked the personnel, ability and financial wherewithal to perform a TELRIC based study. Finally, the RLECs contended that the CMRS Providers' assertions that 47 C.F.R. 51.505(e) imposes an absolute obligation upon Ellerbe to perform its own cost study and that the Commission lacked the authority to modify the application of TELRIC requirements to an RLEC are simply wrong under federal law and FCC requirements.

CMRS PROVIDERS: The CMRS Providers incorporated their prior arguments regarding this Finding of Fact by reference.

ALLIANCE: The Alliance did not file comments on the Finding of Fact.

EMBARQ: Embarq did not file comments on the Finding of Fact.

PUBLIC STAFF: The Public Staff stated that the *Modification Order* did not suspend Ellerbe's obligation to prepare a cost study, but it did allow RLECs to pool their resources to produce a study that more closely resembled TELRIC than if the RLECs individually attempted to conduct the study. Ellerbe's decision to adopt the Randolph study was reasonable and prudent given the fact that Ellerbe does not have the personnel, expertise or financial means to conduct a study. Indeed, the cost of employing a consultant to conduct the study would approach or exceed the total reciprocal compensation that Ellerbe would receive from all CMRS Providers in 2004.

REPLY COMMENTS

RLECs: The RLECs did not file reply comments on this issue.

CMRS PROVIDERS: The CMRS Providers noted that AT&T Mobility and Ellerbe have settled this issue and that Alltel and Ellerbe have not. Thus, Alltel reiterated its objection to Ellerbe utilizing the Randolph cost study as a surrogate in the absence of a showing in the record that Randolph and Ellerbe are similarly situated.

ALLIANCE: The Alliance did not file reply comments on this issue.

EMBARQ: Embarq did not file reply comments on this issue.

PUBLIC STAFF: The Public Staff did not file reply comments.

TWTC AND COMPSOUTH: TWTC and CompSouth did not file reply comments on this issue.

VERIZON WIRELESS: Verizon Wireless did not file reply comments on this issue.

DISCUSSION

In Docket No. P-100, Sub 159, the Commission permitted the RLECs to develop a modified cost study to determine the appropriate reciprocal compensation rate using (in addition to others) the following Guideline:

> 2. The cost data may be a surrogate of the company's cost, but should be forward-looking and reflect an efficient network to the extent practicable.

Ellerbe opted to adopt Randolph's cost study as a surrogate for its costs in determining the appropriate reciprocal compensation rates. Ellerbe took this approach because it could not have performed its own TELRIC study due to the cost of such a study.

In the *RAO*, the Commission found that Ellerbe has only 12 employees, none of whom have the knowledge or experience necessary to conduct such a study; that Randolph is twice as big as Ellerbe and that, therefore, Ellerbe's costs were likely to be greater than Randolph's; and that it was more prudent for Ellerbe to adopt the cost study of another RLEC that most closely approximates Ellerbe's size and circumstances than to bear the cost of engaging a third party consultant to perform an Ellerbe-specific cost study.[1] The Commission rejected the CMRS Providers' objection to Ellerbe's proposal to adopt Randolph's cost study because Randolph relied upon data derived from NECA average schedule companies that utilized embedded (historical) data rather than strict forward looking cost data in developing its cost studies. The Commission noted that it had previously rejected this contention concerning the merits of the Randolph study and approved of the Randolph study as modified therein.

After carefully reviewing the evidence and the arguments advanced by the parties in this proceeding, the Commission held in the *RAO* that:

> [T]he Commission did not intend for its exemption of Ellerbe from the necessity of producing a TELRIC-compliant cost study to mean that Ellerbe must still utilize TELRIC-compliant rates. Instead, the Commission determines that the rates should, to the extent practicable, reflect the costs and manner in which Ellerbe is providing service. Randolph's cost study provides a reasonable and cost effective surrogate for the cost and manner in which Ellerbe is providing service. For these reasons, Ellerbe is justified in using Randolph's cost study with the adjustments herein identified as a surrogate despite the differences in Randolph's and Ellerbe's sizes and that fact that Randolph's study is based upon NECA averages, which are not based strictly upon forward looking cost data.

This conclusion was consistent with the Commission's decision in Docket No. P-100, Sub 159, which granted the RLECs relief from the requirement that reciprocal compensation rates be established based upon a TELRIC compliant study. In Docket No. P-100, Sub 159, the Commission determined that the RLECs were entitled to relief from these requirements under

[1] In Docket No. P-100, Sub 159, the Commission noted that the cost to Ellerbe of conducting a TELRIC study would approach or exceed the total reciprocal compensation that Ellerbe would receive from all CMRS providers in 2004.

the terms of Section 251(f)(2) and that the Commission was authorized to grant such relief even though the pricing requirements were set forth in Section 252(d) and not Section 251(b). Specifically, the Commission held that "[t]he power to modify a reciprocal compensation obligation necessarily implies a power to suspend a TELRIC rate calculation requirement for good cause shown, given that the relevant statute authorizes *both suspension and modification*." *Modification Order*, p. 14. (Emphasis in original.)

The *Modification Order* did not suspend Ellerbe's obligation to prepare a cost study, but it did allow the RLECs to pool their resources to produce a study that more closely corresponded to TELRIC than if each RLEC were to separately produce a cost study. For the reasons discussed in Findings of Fact Nos. 11 and 12, the Commission approved Randolph's cost study in the *RAO*. With regard to Ellerbe, however, the Commission, after carefully examining the record and determining the size, access lines, and expertise of Ellerbe and its employees, determined that the expense to retain a consultant to conduct a TELRIC compliant study would approach or exceed the total reciprocal compensation that Ellerbe would receive from all CMRS Providers in 2004. Accordingly, the Commission accepted Ellerbe's contention that it was more prudent to adopt the cost study of Randolph than to require Ellerbe to perform an Ellerbe-specific study. The Commission reached this conclusion with the full understanding that use of a surrogate cost study could result in the arguments here advanced by the CMRS Providers that the resulting rates are not reflective of Ellerbe's costs because of the differences between the two companies.

In fact, under those circumstances, differences are to be expected, since a surrogate is a similar but, imperfect, substitute for the original. Despite these imperfections, the Commission concluded that Randolph's cost study was a *reasonable* surrogate for Ellerbe and that the study was a reasonable representation of Ellerbe's costs upon which the Commission could base its decision. Aside from pointing out the obvious dissimilarities regarding the size of the two companies, which the Commission was aware of and considered fully in making its decision, the CMRS Providers have not presented any evidence or argument to suggest that the conclusion that was reached was unreasonable in light of those circumstances that the Commission faced and the decision that was rendered in Docket No. P-100, Sub 159. Thus, the Commission reaffirms its conclusion that it was reasonable and appropriate for Ellerbe to adopt Randolph's alternative cost study results, with the adjustments therein identified.

CONCLUSIONS

The Commission finds it appropriate to deny the CMRS Providers' objections to Finding of Fact No. 23 and to affirm the *RAO* decision.

IT IS, THEREFORE, ORDERED as follows:

1. That, in accordance with the Commission's January 24, 2001 and November 3, 2000 Orders issued in Docket No. P-100, Sub 133, the CMRS Providers and the RLECs shall jointly file the required Composite Agreements by no later than Friday, January 30, 2009.

2. That the Commission will entertain no further comments, objections, or unresolved issues with respect to issues previously addressed in this arbitration proceeding.

3. That the Commission denies all objections to Findings of Fact Nos. 1, 2, 4, 8, 11, 12, 23, 27, and 28, thereby upholding and affirming its original decisions regarding these issues.

4. That, with respect to Finding of Fact No. 8, the Commission finds it appropriate to allow MebTel to include an additional $56 per line for land and building investment in its alternative cost study for a total switch investment figure of $514 per line.

5. That the Commission finds it appropriate to grant MebTel's objections to Finding of Fact No. 10, and that, therefore, the appropriate usage sensitive switching factor to be applied to MebTel's total investment is 49.75 percent.

6. That the Commission does not find it appropriate to allow Randolph to reflect an updated number of access lines and projected usage in its alternative cost study in connection with Finding of Fact No. 11.

7. That the Commission finds with respect to Finding of Fact No. 17 that the appropriate usage sensitive switching cost percentage to be included in Randolph's alternative cost study is 52.6 percent.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Culpepper separately concurs with the Majority's decision on Finding of Fact No. 1.

Chairman Finley and Commissioner Joyner dissent from the Majority's decisions on Findings of Fact Nos. 1 and 2.

bp123108.01

DOCKET NO. P-21, SUB 71
DOCKET NO. P-35, SUB 107
DOCKET NO. P-61, SUB 95

Commissioner William T. Culpepper, III, concurring:

As a member of the majority, I fully concur with the Commission's decision to uphold and affirm its original decision regarding the issues resolved by the Commission's Finding of Fact No. 1. However, I write separately to express my opinion that the single POI solution we have adopted is not only appropriate because it is based on the equities in these dockets but also because it is mandated by the law. In other words, it is my belief that in all instances there is required to be but a single POI between two interconnecting telecommunications carriers and, in the event they are unable to agree as to its location, then that issue is one to be properly decided by the Commission based upon facts and equities presented to it, and the law applicable thereto, in the course of a Section 252 arbitration proceeding.

This issue in this docket is concerned with the location of the POI between the CMRS Providers and the RLECs in a case of indirect interconnection. In its RAO, the Commission (with a dissent) concluded that, as a matter of law, there is to be a single POI. This is also the position of the RLECs and the Public Staff. The CMRS Providers and their allies vigorously disagree.

Practically speaking, the primary significance of the location of the POI in the context of indirect interconnection is that, as a legal matter, the location of the POI determines who bears responsibility for the payment of transit charges to the third party carrier. The discussion in Finding of Fact No. 2 examines the transit cost responsibility question in greater detail.

Regrettably, there has been no *explicit* guidance on this point from the FCC. This is not to say, however, that there has been no guidance at all. In its Further Notice of Proposed Rulemaking about "Developing a Unified Intercarrier Compensation Regime," CC Docket 01-92 (Released March 3, 2005) (*Intercarrier Compensation NPRM*), the FCC wrote at Paragraph 91 that "issues related to the location of the POI and the allocation of transport costs are some of the most contentious issues in interconnection proceedings. In particular, the record suggests that there are a substantial number of disputes related to how carriers should allocate interconnection costs, particularly when the physical POI is located outside the calling area where the call originates *or when carriers are indirectly interconnected*. These disputes arise in part because of a lack of clarity among the various rules governing the costs of interconnection facilities and the relationship of these rules **to the single POI rule**." (Emphasis and bold added). Thus, while the FCC has not yet ruled in this docket, there can be little doubt that the FCC's operating assumption is the "the single POI rule."[1]

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[1] *Contra, Atlas* at 1270 in the historical recitation: "When a RTC customer places a call to a CMRS customer, the call must first pass from the RTC network through a point of interconnection with the SWBT network [the third-party transit carrier]. SWBT then routes the call to *a second point of interconnection* between its network and the CMRS network." [Emphasis added]. The Intercarrier Compensation Rulemaking order requesting comment came out shortly before the *Atlas* order came out but was not referenced in *Atlas*.

In addressing reciprocal compensation in its First Report and Order, FCC 96-325, CC Docket Nos. 96-98, 95-105, para. 1034 (Aug. 8, 1996), the FCC wrote that under a typical reciprocal compensation agreement between two carriers, the carrier on whose network the call originates bears the cost of transporting the telecommunication traffic to **the point of interconnection** with the carrier on whose network the call terminates. Id. (Bold emphasis added).

Furthermore, "transport" in the context of reciprocal compensation obligations is defined as "the transmission and any necessary tandem switching of telecommunications traffic subject to Section 251 (b)(5) of the Act from **the interconnection point** between **the two carriers** to the terminating carrier's end switch .... 47 C.F.R. Sec. 51.701(c) (Bold emphasis added).

Additionally, Sec. 51.5 of the FCC rules defines "Interconnection" as "the linking of **two networks** for the mutual exchange of traffic ...." (Bold emphasis added)

Indeed, the FCC use of the phrase "two networks" in the definition of interconnection and the phrase "the one POI rule," referenced above, strongly implies that the third party transit carrier's network is to be viewed as a virtual part of one or the other of the parties' networks. Thus, there are two networks—that of the CMRS Provider and that of the RLEC—not three networks. And there is one POI, not two. The two networks/one POI paradigm is conceptually perfectly consistent with the statutory language and FCC rules as to the general telecommunications carrier Section 251(a)(1) duty to interconnect directly or indirectly.

The CMRS Providers and their allies, of course, argue otherwise. They advocate the "two-POI rule." Their touchstone of analysis is the *Atlas* case. The nub of that analysis is contained in the following paragraph in *Atlas*:

> The fallacy of the RTC's argument is demonstrated in a number of ways. The RTCs contend that the general requirement imposed on all carriers to interconnect 'directly or *indirectly*.' (47 U.S.C. 251 (a) (emphasis added) is superseded by the more specific obligations under Sec. 251(c)(2). Yet, as noted above, the obligation under Sec. 251(c)(2) applies only to the far more limited class of ILECs, as opposed to the obligation imposed on all telecommunications carriers under Sec. 251(a). The RTCs interpretation would impose concomitant duties on both the ILEC and a requesting carrier. This contravenes the express terms of the statute, identifying only ILECs as entities bearing additional burdens under Sec. 251(c). We cannot conclude that such a provision, embracing only a limited class of obligees, can provide the governing framework for the exchange of local traffic. (*Atlas* at 1265)

In the RAO in these dockets, the Commission rejected the analysis employed by the Tenth Circuit as "flawed and unpersuasive." While the Tenth Circuit engaged in statutory interpretation, it did not clearly articulate the interpretive principles it relied on. The Tenth Circuit certainly never engaged what the FCC had to say in its *Intercarrier Compensation NPRM* where it specifically referred to its "single POI rule." Instead, the crux of the Tenth Circuit's analysis is its argument that Section 251(c)(2) applies only to the limited class of ILECs while

Section 251(a) applies to all telecommunications carriers. The Tenth Circuit said it could not conclude that "such a provision embracing a limited class of obligees can provide the **governing framework** for the exchange of local traffic." (Emphasis added) But Section 251(a) through (c) contains many parts. As they are to be construed *in pari materia*, the more accurate characterization is that they must *all* go together to constitute "the governing framework." The governing framework for the exchange of local traffic is provided by the totality of duties as they pertain to different classes of providers.

Furthermore, as the Public Staff observed in its April 25, 2008, Comments on Objections:

> In the instant case concerning indirect interconnection using a third party provider, the tandem and transit facilities of the third party provider become a virtual part of the CMRS Providers' networks, because the third party provider's facilities are used to connect with the POI on the RLECs' networks. The CMRS Providers pay for the third party provider's transiting facilities in lieu of the facilities they would have needed if connecting directly with the RLECs. The cost of transiting facilities is recovered through reciprocal compensation rates charged by the CMRS Providers to the RLECs, just as the cost of direct connection facilities would be. Financial responsibility then rests for each party on its own side of the POI, and each party pays reciprocal compensation to the other to cover the cost of completing the call beyond the POI. Accordingly, the Commission correctly applied the ALLTEL case to the instant case. (At 9-10).

In conclusion, however much the CMRS Providers might deplore the implications of the one-POI requirement, at least the one-POI requirement has the virtue that it is supported in the text of the statute and FCC rules construed in the light of accepted principles of statutory interpretation. As noted, the one-POI requirement is the FCC's operating assumption. By contrast, there is absolutely no textual support for the two-POI requirement in statute or the rules. The Tenth Circuit did not even consider such principles in its analysis, but rather inferred its own conclusion based on its reading of the statute according to its own lights.

/s/ William T. Culpepper, III
Commissioner William T. Culpepper, III

DOCKET NO. P-21, SUB 71
DOCKET NO. P-35, SUB 107
DOCKET NO. P-61, SUB 95

Chairman Edward S. Finley, Jr. dissents from Finding of Fact Nos. 1 and 2 and the resolution of Matrix Issues 1 and 4.

I renew my opinion that the RLECs should bear financial responsibility for the costs of transport and termination they incur in delivering local calls originating on their networks to the point of interconnection between the intermediate carrier (AT&T) and the CMRS network where the interconnection is indirect. Such originating transport and termination costs include transit fees assessed by the intermediate carrier. Such transit fees are not costs incurred by the CMRS carriers to be reimbursed through reciprocal compensation payments from the RLECs that must be calculated on an asymmetrical basis.

The majority now acknowledges that the rationale and legal justification for the resolution of these issues in the December 20, 2007 RAO were in error. Nonetheless, they persist in relying upon the discredited "single POI" theory[1] and thereby resolve these issues without adhering to established federal precedent.

The errors relied upon by the majority in addressing these issues originated in the October 8, 2004 RAO in the Alltel case.

In Alltel the Public Staff cited the Fourth Circuit's opinion in MCIMetro Access Transmission Service, Inc. v. BellSouth Telecommunications, Inc. 352 F.3d 872 (4th Cir. 2003) (BellSouth) as controlling authority for the proposition that the ILEC in that case should bear the costs of transit charges as part of the costs of originating transport on ILEC originated calls. The Commission in its Alltel RAO recited the Public Staff position, then rejected it while at the same time inexplicably also purporting to rely on BellSouth for doing so:

> While the Fourth Circuit ruling applies specifically to a case involving direct interconnection, the Commission cannot find a basis for distinguishing between direct and indirect interconnection. . . . Therefore, the decisions concerning direct interconnection are equally applicable to indirect interconnection. For this reason, the Commission believes it should apply the holding and reasoning of the Fourth Circuit opinion regarding direct interconnection and find that the originating carrier is responsible, both technically and financially, for transporting calls to the POI [which must be located on the ILEC's network and, therefore, leave any transit charges from an intermediate carrier the financial responsibility of the CMRS]
> . . .

October 8, 2004 Order, Docket No. P-118, Sub 130, p.13

The BellSouth case did not involve indirect interconnection, and it is unclear and not explained why the Commission concluded that the holding in BellSouth supported making the terminating CMRS carrier responsible for transit charges assessed by an intermediate carrier on ILEC originating traffic. In my view, BellSouth supported no such conclusion, and the Commission misapplied the BellSouth reasoning.

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[1] As with December 20, 2007 RAO, the Commission majority refuses to recognize the physical interconnection between the intermediate carrier and the CMRS carriers located beyond the RLEC network boundary. The Commission majority treats the intermediate carrier link as part of the CMRS network for both RLEC and CMRS originated traffic.

In Alltel the Commission proceeded to articulate its putative single POI requirement for indirect interconnection:

> For two carriers to interconnect, either directly or indirectly, they must have a POI—that is, a point at which traffic is physically exchanged between the two carriers' networks. However, in defining the POI, the Commission does not have the authority to do what the Parties are free to do by agreement, i.e., the Commission cannot define the POI to be a point outside of the ALLTEL network. The FCC rules provide that an ILEC shall provide interconnection with its network at any technically feasible point within the ILEC's network. 47 C.F.R. 51.305(a)(2).

Id. at 14 (emphasis in the original).

The Commission's putative single POI rule contradicts BellSouth, incorrectly converts an ILEC obligation in 47 U.S.C. 251(c)(2)(B) into a competing carrier limitation and unlawfully ignores the requirements of 47 U.S.C. 251(a), which expressly authorizes indirect interconnection. Indirect interconnection, by definition, involves two--not one--points of interconnection.

The single POI theory arises from the Commission's misunderstanding of the duties imposed in 47 U.S.C. 251(c)(2)(B) and FCC Rule 47 C.F.R. 51.305(a)(2), which repeats them. That section and rule impose on incumbent carriers

> the duty to provide for the facilities and equipment of any requesting telecommunications carrier, interconnection with the local exchange carrier's network (A) for the transmission and routing of telephone exchange service and exchange access; (B) at any technically feasible point with the carrier's network.

The Fourth Circuit establishes clearly in BellSouth that 251(c)(2)(B) and Rule 305 have nothing whatsoever to do with assigning cost responsibility for the recurring termination and transport costs such as those at issue in Alltel and in this case.

> In its Notice of Proposed Rulemaking (NPRM) preceding the issuance of the Local Competition Order, the FCC sought comment on whether the term "interconnection" [as required in 251(c)(2)(B)] might refer "only to the physical linking of two networks or to both the linking of facilities and the transport and termination of traffic." Local Competition Order, 11 FC.C.R. at 15588-89 ¶ 174. The FCC adopted the former definition: "We conclude that the term "interconnection" under Section 251(c)(2) refers only to the physical linking of two networks for the mutual exchange of traffic." Id. at 15590 ¶ 176. Therefore, because the cost of interconnection is only the one-time cost associated with the physical act of linking one network to

> another and not the recurring cost of transport and termination of traffic, the charge imposed by BellSouth here cannot be characterized as a "cost of interconnection" that is permitted by FCC rules.

352 F.3d at 878-79.

The Fourth Circuit in BellSouth ruled that the incremental transport and termination costs that the ILEC sought to shift to the competing carrier in delivering traffic to the terminating carrier's network must be borne by the ILEC. The Fourth Circuit based its determination on the reciprocal compensation requirement of 47 U.S.C. 251(b)(5) and the FCC Rule 703 implemented thereunder, not upon section 251(c)(2)(B) and Rule 305, which the Commission based its decision on in Alltel:

> Rule 703(b) is unequivocal in prohibiting LECs from levying charges for traffic originating on their own networks, and, by its own terms, admits no exceptions. Although we find some surface appeal in BellSouth's suggestion that the charge here is not reciprocal compensation, but rather the permissible shifting of costs attending interconnection, the FCC, as noted above, has endorsed cost shifting related to interconnection only as it relates to the one-time costs of physical linkage, and in doing so, expressly declined the invitation to extend the definition of "interconnection" to include the transport and termination of traffic.

352 F.3d at 881.

When the Commission in Alltel based its single POI holding on FCC Rule 305 and 47 U.S.C. 251(c)(2)(B), it did so in complete disregard and violation of the Fourth Circuit's pronouncements in BellSouth.

A simple, common sense reading of 47 U.S.C. 251(c)(2)(B) leads to the same conclusion. This section imposes only on ILECs a duty to permit physical interconnection of a competing new entrant's facilities at at least one technically feasible point on the ILEC's network, upon the CLEC's request. The section imposes no duty on the CLEC or other new entrant, establishes no requirements for a single POI, and leaves the ILEC obligation to permit interconnection on its network to the CLEC's requests. This section by its express terms does not preclude points of interconnection beyond the ILEC's network.[1] The statute is not ambiguous and requires no interpretation.

The Commission in Alltel likewise ignores 47 U.S.C. 251(a), which, again, unequivocally imposes upon all carriers, including but not limited to ILECs, the duty to interconnection directly or indirectly. Indirect interconnection by definition involves more than

[1] In this case the undisputed evidence is that Mebtel has a one way direct trunk linking its network to ATT Mobility's for delivery of Mebtel traffic. Obviously, ATT Mobility delivers its traffic to Mebtel through other means. Tr. p. 395, ll. 2-10. It is not possible to describe this situation as one of "a single POI."

one point of interconnection. "Interconnection is indirect when the attachment occurs through the facilities or equipment of an additional carrier or carriers." Advanced Telecommunications Capability, 15 F.C.C. Rcd. at 17845, n. 198. It is not possible to have three carriers involved in completing a call without having at least two points of physical interconnection.

Alltel was decided incorrectly and the panel majority in the RAO in this case repeated this error in following it. The Commission majority, upon review of the RAO, at least acknowledges that the legal justification for the RAO decision is indefensible and that the RLECs should be ultimately responsible for transit fees incurred on RLEC originated traffic. Nonetheless, still in disregard of controlling federal law and the record evidence, the Commission majority relies on the single POI principle, albeit in a slightly different incarnation[1], to make the terminating CMRS carriers responsible in the first instance for payment of transit charges on RLEC originated traffic. And unless the CMRS carriers are willing to conduct cost studies and apply for asymmetrical reciprocal compensation rates, they still ultimately will bear the costs of the transit fees.

The uncontradicted evidence of record is that the decision of the RLECs to transport RLEC originated traffic through the tandem of the intermediate carrier and deliver it in that fashion to the CMRS carrier is the RLECs'.

> Q. And would you agree with me that the RLEC normally won't choose one-way direct trunks because it's cheaper to send the traffic through the third-party network than to install those one-way trunks?
>
> A. (RLEC witness Thaxton) Due to traffic volumes, yes.
>
> Q. So the RLEC would be choosing indirect interconnection because it makes the most economic sense for the RLEC, correct?
>
> A. That is correct.

Tr. p. 120, ll 7-15.

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[1] Actually the new single POI principle is nothing but the old one slightly repackaged. The new POI principle is the Public Staff "virtual network" theory where the intermediate carriers network is a "virtual" part of the CMRS network for both RLEC and CMRS originated calls. "The CMRS providers pay for the third party transiting facilities in lieu of facilities they would have needed if connecting directly with the RLECs." Majority opinion p. 17. "The two-POI solution presuppose the existence of three different networks, while the one-POI solution makes do with two—the transit network in this case being considered a virtual part of the CMRS providers' network." Majority opinion, p. 13. This "virtual network" theory is like the one expressly rejected by the Fourth Circuit in BellSouth when it rejected BellSouth's cost shifting argument because 47 U.S.C. 251(c)(2) was inapposite while 47 U.C.S. 251(b)(5) was controlling. "Although we find some surface appeal in BellSouth's suggestion that the charge here is not reciprocal compensation, but rather the permissible shifting of costs attending interconnection, the FCC, . . . has endorsed cost shifting related to interconnection only as it relates to the one-time costs of physical linkage, and in doing so, expressly declined the invitation to extend the definition of "interconnection" to include the transport and termination of traffic." 352 F.3d at 881.

Q. Cingular would not have made Randolph's choice to route the traffic through the third party tandem, would it?

A. No.

Id. p. 115, ll 5-8.

As the RLECs chose indirect interconnection for RLEC originated traffic, there certainly is no justification for asserting for RLEC originated traffic that the transit function performed by the intermediate carrier is a transport and termination function on behalf of the CMRS carrier, so that the CMRS carriers must initially bear these costs and can only be reimbursed through reciprocal compensation payments from the RLEC. Instead, pursuant to 47 C.F.R. 51.703, the transit fees are costs of transport and termination to be borne from the outset by the RLEC as costs of delivery of their traffic to the CMRS's network.

Even if the record evidence could be ignored and the decision to interconnect indirectly had been solely the decision of the CMRS carrier, no justification exists for treating the point of interconnection between the RLEC and the intermediate carrier for RLEC originated traffic as the point for determining where the RLEC's duty to transport and terminate ends and where the CMRS's duty to transport and terminate begins. In interpreting Section 251(a), the FCC has held that it is the competitive carriers—not the incumbent—that have the right to choose whether to interconnect directly or indirectly, "based upon their most efficient technical and economic choices." In re Implement of the Local Competition Provisions in the Telecommunications Act of 1996, 11 F.C.C. R. 15499 (1996) at ¶ 997 ("First Report and Order"). 47 C.F.R. § 20.11(a) establishes that the wireless carrier has the right to choose its preferred method of interconnection—direct or indirect: "A local exchange carrier must provide the type of interconnection reasonably requested by a mobile service licensee or carrier."

The Commission majority is not justified in circumventing this choice by artificially moving the point of interconnection for purposes of reciprocal compensation responsibility for RLEC originated traffic to the point where the RLEC's network interconnects with the intermediate carrier's network. No evidence exists that the choices for the points of interconnection or for the indirect linking of the networks impose uneconomical or technically inefficient burdens on the RLECs. There is no support in the record that the CMRS carriers have arbitrarily selected points of interconnection at the far reaches of the MTA, thus asking the RLECs to incur exorbitant transit fees. That would be a different case and the issue would be whether the CMRS's selection of the location for the second POI was reasonable and prudent.

Resort to an invitation to the CMRS carriers to request asymmetrical reciprocal compensation rates with the penalty for failing to do so CMRS responsibility to absorb the transit fees on RLEC originated traffic is equally impermissible. This new remedy is a thinly veiled effort to leave the responsibility for the transit fees at issue on the CMRS carriers based on an assumption that CMRS transport and termination costs are lower than those set for the RLECs so a CMRS request for asymmetrical rates will not be forthcoming. While the CMRS carriers now have and have had the right to request asymmetrical reciprocal compensation rates, they have, for reasons satisfactory to themselves, chosen not to exercise that right.[1] 47 C.F.R. §51.711(b). Instead, they have exercised their right, likewise available to them, to use as a proxy the reciprocal compensation rates they pay to the RLECs based on the RLECs' costs for transporting and terminating CMRS originated traffic. 47 C.F.R. §51.711(a). These are rights the Act and FCC regulations give them, and the Commission is without authority to deprive them of these rights, whatever the motive.

Moreover, the remedy of asymmetrical reciprocal compensation rates as envisioned by the majority does not work. For the rates that both types of carriers pay to be fair and equitable, if transit fees are CMRS costs to be reimbursed through reciprocal compensation payments for RLEC originated calls, the transit charges assessed on CMRS originated traffic must be included as RLEC termination and transport costs recoverable from the RLECs as an element of reciprocal compensation the CMRS carriers pay. At present the transit charges are not so included. Therefore, in determining which terminating costs are higher, the RLECs' or the CMRS', as 47 C.F.R. 711(b) contemplates, the components giving rise to the costs are mismatched, and an essential element is missing from the RLECs' costs.

The remedy adopted by the majority is a misuse of asymmetrical reciprocal compensation. When new entrants to the local exchange market determine that the costs they incur in transporting local calls from the POI where they receive calls that originate on the ILEC's network and in terminating the call at their switch exceed that of the incumbent in performing the same function, the new entrant is authorized to seek to have its terminating costs established on an analysis of such costs rather than to take as an proxy of its costs the ILEC's costs.

Asymmetrical reciprocal compensation is a device to ease competitive entry, not one to impose obstacles to entry. The new entrant is to be permitted to establish its costs on the basis of the greater of its costs or the ILEC costs for undertaking identical functions. The new entrant is not ever obligated to resort to asymmetrical reciprocal compensation where its costs are lower than the ILEC's costs, as the majority assumes here.

> A state commission may establish asymmetrical rates for transport and termination of telecommunications traffic only if the carrier other than the incumbent LEC... proves to the state commission on the basis of a cost study
> using the forward-looking economic cost based pricing methodology
> described in §§ 51.505 and 51.511, that the forward-looking costs for a
> network efficiently configured and operated by the carrier other than the incumbent LEC
> ...exceed the costs incurred by the incumbent LEC...
> and, consequently, that such that (sic) a higher rate is justified.

47 C.F.R. § 51.711(b).

Moreover, whether the new entrant reciprocal compensation reimbursement payment is symmetrical or asymmetrical, the components of the transport and termination functions for both

[1] The evidence indicates that most of the local calls exchanged among the carriers originate on the CMRS networks and terminate on the RLECs'.

the ILEC and the new entrant should be the same. If transit charges on ILEC originated traffic are to be a new entrant's terminating costs to be reimbursed through ILEC reciprocal compensation payments, transit charges on new entrant originated traffic should be terminating costs to be reimbursed through reciprocal compensation payments made to the ILEC from the new entrant also. Asymmetry should arise from differing costs for comparable functions not from differing assignments of functions to complete calls between the ILEC and new entrant carriers.

This arbitration was correctly filed and has been correctly presented and argued on the understanding that the reciprocal compensation rates would be symmetrical, would be based on RLECs' costs and that the point(s) of interconnection for establishing the rights and obligations of the parties for financial responsibility for reciprocal compensation would be determined by the Commission on the basis of existing controlling law and the evidence of record. This case has been pending before us for a number of years. No justification exists for refusing to resolve the non cost issues on the record now before us while inviting the CMRS carriers to file for asymmetrical rates. Based on FCC regulation, 47 C.F.R. § 51.711(b), the CMRS carriers must comply with TELRIC requirements in developing such rates, even through the RLECs are not so required based on this Commission's orders relieving them of this responsibility. We have liberally construed those orders in this arbitration. I find this solution untenable.

Three United States Circuit Courts of Appeal in addition to the Fourth Circuit have now rendered opinions addressing the interplay between the reciprocal compensation and related duties under 47 U.S.C. 251(b) and interconnection requirements of 47 U.S.C. 251(c). All four undermine both the decision of the panel majority and the Commission majority in this case. It is one thing for two members of the Commission panel to disregard the holdings of federal circuit courts in favor of existing Commission precedent. It is quite another for the Commission majority on review, after acknowledging that the "single POI" justification for the Alltel decision and the RAO in this docket is erroneous, to nonetheless determine not to follow those decisions and to base its determination on review on yet another variant of a "single POI" theory.

The operative facts in the Tenth Circuit's decision in Atlas Telephone v. Oklahoma Corporation Comm'n, 400 F. 3d 1256 (10th Cir. 2005) (Atlas) are indistinguishable from those at issue here. In both cases the RLECs and CMRSs agreed to interconnect indirectly via the tandem of an intermediate carrier.[1] The RLECs in Atlas argued that they should not be

[1] The Commission majority asserts that it is unable to discern from the Atlas opinion whether the RLECs and CMRSs there "had agreed to a two-POI solution, the Oklahoma PUC has imposed it without objection from the parties or the Tenth Circuit simply assumed it." Majority Opinion p. 12. The majority asserts that "in Atlas the two-POI conclusion seems to be assumed rather than proven." Id. The majority refuses to take the Tenth Circuit at its word when describing the two point interconnection in its statement of facts on page 1259 and ignores the Tenth Circuit's repeat of the agreed upon two points of interconnection on pages 1260 and 1261: "Under these reciprocal compensation agreements, the originating network bears the cost of transporting telecommunications traffic across SWBT's network to the point of interconnection with the terminating network. The originating network is then required to compensate the terminating network for terminating the call." (emphasis added) For purposes of the Tenth Circuit's holding, there can be no question that the network architecture was interconnected in that case in the same way it is interconnected in this case.

While I can appreciate the majority's discomfort with the Atlas holding, I do not recall an instance where a tribunal presumptively dismissed the facts a court relied upon in reaching its holding because the facts had not been responsible for a portion of costs on RLEC originated traffic through reliance on the "single POI" theory. "[T]he RTCs do not argue that the CMRS providers must directly connect to their networks. Rather, the essence of their argument is that RTCs cannot be forced to bear the additional expense of transporting traffic bound for a CMRS provider across the SWBT network. Under their interpretation, RTCs are only responsible for transport to a point of interconnection on their own network." 400 F.3d at 1265 n. 9. Adhering to the same logic as the Fourth Circuit in BellSouth, the Tenth Circuit dismissed the single POI logic:

> The RTCs first contend that 47 U.S.C. § 251(c)(2) mandates that the exchange of local traffic occur at specific, technically feasible points within the RTC's network, and that this duty is separate and distinct, though no less binding on interconnecting carriers, from reciprocal compensation arrangements mandated by § 251(b)(5). We simply find no support for this argument in the text of the statue or the FCC's treatment of the statutory provisions. Section 251(c)(2) imposes a duty on the ILECs to provide physical interconnection with the requesting carriers at technically feasible points within the RTCs' networks. By its terms, this duty only extends to ILECs and is only triggered on request.

Id. (emphasis in the original)

The Tenth Circuit held that "[b]ecause we hold that 47 U.S.C. § 251(c)(2) does not govern interconnection for purposes of local exchange of traffic, the RTCs' argument that CMRS providers must bear the expense of transporting RTC-originated traffic on the SWBT network must fail." 'Id. at 1266, n. 11. In this regard the Tenth Circuit affirmed the District Court's holding 'that reciprocal compensation obligations apply to all calls originated by an RTC and terminated by a wireless provider within the same major trading area, without regard to whether those calls are delivered via an intermediate carrier.' 309 F. Supp.2d at 1310." Id. at 1261.

As far as I am concerned, adherence to the holding of Atlas in the indirect interconnection context that the RLECs bear responsibility for all costs incurred in delivering their traffic to the CMRS network prevents the remedy adopted by the majority that the CMRS carriers must first bear this expense and can only obtain reimbursement from the RLECs through asymmetrical reciprocal compensation rates.

Those Commissioners adhering to the discredited single POI theory for indirect interconnection inconsistently vacillate in their efforts to avoid the holding and reasoning of Atlas. On the one hand, they acknowledge that the facts are identical to those in this case and

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"proven." For purposes of the precedential nature of an opinion of a United States Court of Appeals, the facts recited and relied upon in its published opinion are "the facts," proven, assumed or otherwise. The pertinent question to ask is not how to describe the indirect interconnection in Atlas but how it is permissible under 47 U.S.C. Sections 251(a) and (b) to move the POI from where it is actually established in this case by agreement of the parties and to pretend it is on the RLEC's network as the majority unlawfully has done.

that the holding demands the opposite result they desire to reach, so they dismiss Atlas as being "flawed and unpersuasive" and with only "superficial appeal." RAO pp. 15-18. On the other hand they seek to distinguish it:

> The Commission has closely read each case and notes that none of the cases cited by the CMRS providers expressly state (sic) that the originating carrier has an obligation to pay a transit charge assessed by a third party carrier in addition to paying reciprocal compensation. In fact in the Atlas case, the Tenth Circuit, consistent with the decision adopted in the RAO, held that the originating rural carrier had an obligation to compensate the terminating CMRS carrier under the reciprocal compensation regime for traffic transported to the POI of the CMRS provider. Atlas 400 F. 3d 1256 at p. 1267 (2005) (emphasis in the original).

Majority Opinion, p. 21.

No valid reading of Atlas can support this quote from the majority opinion. For RLEC originated traffic the Tenth Circuit viewed the POI at which the CMRS carrier receives the calls and at which point its transport and termination service begins as the point of interconnection between SWBT and the CMRS carriers:

> When the RTC customer places a call to a CMRS customer, the call must first pass from the RTC network through a point of interconnection with the SWBT network. SWBT then routes the call to a second point of interconnection between the network and the CMRS network. The call is then delivered to the CMRS customer. In contrast, where the RTC and CMRS networks are directly connected, the call would pass only through a single point of interconnection.

400 F. 3d at 1260.

Also,

> Under these reciprocal compensation agreements, the originating network bears the cost of transporting telecommunications traffic across SWBT's network to the point of interconnection with the terminating network. The originating network is then required to compensate the terminating network for terminating the call.

400 F.3d at 1260-61.

According to the Tenth Circuit, the reciprocal compensation payments from the RLECs to the CMRS carriers were to reimburse the CMRSs for cost of transport and termination from the second point of interconnection (between SWBT and the CMRS) to the CMRS switch. "Because we hold that 47 U.S.C. § 251(c)(2) does not govern interconnection for the purposes of local exchange traffic, the RTCs' argument that CMRS providers must bear the expense of transporting RTC-originated traffic on the SWBT network must fail." 408 F3d at 1266, n. 11.

The majority's cite to page 1256 of Atlas provides no support for the proposition that transit fees on RLEC originated traffic are costs to be reimbursed through RLEC reciprocal compensation payments instead of as RLEC originating transport and termination costs. When the Tenth Circuit addresses the "reciprocal compensation regime" on page 1256 and elsewhere, it is distinguishing the broader reciprocal compensation mechanism from the access charge mechanism that the RLECs were advocating in Atlas or a bill and keep mechanism such as the RLECs and CMRSs apparently have been using before this arbitration as the appropriate intercarrier compensation mechanism.

The majority's failure to appreciate the distinction between a reciprocal compensation regime as opposed to an access charge or bill and keep regime for purposes of intercarrier compensation and the reciprocal compensation payment made by the originating carrier to compensate the terminating carrier for the services the terminating carrier provides after receiving the call at the POI pervades the RAO and the majority opinion. For example, on page 19-20 the majority inaccurately accuses the CMRS carriers of "conflating" the requirement that the originating carrier pay reciprocal compensation with the duty of the originating carriers to bear the responsibility for transit fees on such traffic. There is no conflation whatsoever. For originating traffic where interconnection is indirect, transit fees are cost of originating transport and termination in delivering traffic to the second POI where the terminating carrier receives it. It is not part of the terminating carriers' terminating costs to be reimbursed through the reciprocal compensation payment. This is why 47 C.F.R. 51.703 controls and the RLECs must pay. It is the majority that is guilty of conflation when it treats transit fees on RLEC originating traffic assessed to transport calls to the POI with the terminating carrier as a CMRS termination cost while treating transit fees on CMRS originated traffic as an originating cost.

The majority is fundamentally wrong when it asserts that Atlas is consistent with the RAO. The two holdings reach diametrically opposite conclusions on identical facts. If the majority's decision were logically persuasive and based on sound reasoning, no such invalid assertions would be necessary. And when later in its opinion (p.22) it asserts that Atlas and other opinions require the result it reaches, the majority shows for a final time that its reasoning is completely defective.

The Eighth Circuit in WWC License, L.L.C v. Pub. Serv. Commission, 459 F.3d 880 (8th Cir. 2006) (WWC License), in partial reliance on Atlas, rejected the "single POI" logic argued by the ILEC there. In an effort to avoid another 251(b) duty, dialing parity, the ILEC relied on the theory that the competing carrier did not exchange traffic with the ILEC at a point of interconnection within the ILEC's network.

> Great Plains [the ILEC] emphasizes that §251(b)(3) and the relevant regulation, 47 C.F.R. § 51.207, do not expressly state that a local exchange carrier must deliver locally dialed calls to a point outside the local exchange carrier's network. Great Plains infers from this silence that the duty to provide local dialing parity does not extend beyond the physical bounds of the local exchange network and is therefore dependent upon the existence of a competitor's direct point of interconnection within the local exchange. We believe that this inference is unwarranted. The relevant statutory and regulatory sections are not written in such narrow terms. Rather the Act and the regulation state a broad duty without listing exceptions and without expressly defining a geographic limitation.
>
> . . . .
>
> . . . the statutory provision that imposes the duty to interconnect networks expressly permits direct or indirect connections. 41 U.S.C. § 251(a)(1). Nothing in the Act suggests that Congress intended a carrier's duties to be altered based on the carrier's election to connect indirectly rather than directly. We believe that if Congress intended there to be consequences attendant to choosing an indirect rather than a direct connection, Congress could have made that fact clear. Accordingly, any distinction we might draw based on the existence of a direct connection would be textually unsupported.

459 F.3d at 890-893.

WCV License relies upon the principle that LEC duties imposed by 251(b) are not altered when the carriers exchange traffic indirectly from what these duties would be if the carriers exchange traffic directly. Consequently, because the CMRS carriers in this case could not be forced to conduct cost studies and base reciprocal compensation reimbursement on asymmetrical costs as the only means of receiving reimbursement for costs of transport and termination they incur in delivering RLEC originated traffic to the CMRS switch from the single POI if the traffic were exchanged directly, they cannot be required to conduct cost studies and seek asymmetrical rates in order to be reimbursed for transit charges on RLEC originated traffic simply because the interconnection is indirect.

The fourth federal Circuit Court to address this issue of indirect interconnection is the D. C. Circuit in Mountain Communications, Inc. v. Federal Communications Commission, 355 F. 3d 644 (D.C. Cir. 2004):

> Qwest [the intermediate carrier] incurs costs for switching and routing these [calls originating on the ILECs network] over the Qwest network, and Qwest charged Mountain [the new entrant paging carrier to whom the calls are terminated] for the last of five parts of those expenses—the cost of delivering the call from the Qwest end office switch to Mountain's POI. The FCC allowed Qwest to charge for this service, but indicated that Mountain could seek reimbursement from the originating carrier for whatever charges it paid to Qwest. (citation omitted) Mountain's petition challenged this FCC decision as well, claiming that the charge is arbitrary and capricious because it does not follow the standard practice of charging the cost of calls to the network of the party initiating the call. Mountain insisted that the prospect of reimbursement from the originating carrier was illusory, because Mountain never receives information from Qwest about which carrier initiates any individual call, and it is therefore impossible for Mountain to seek reimbursement from a third carrier. It is undisputed that Qwest need not absorb these costs; the only question is whether Qwest can charge Mountain for one of the five portions of this call or must instead look to the originating carrier for all of the costs. It might well be reasonable for the Commission to authorize Qwest to apportion those costs, but we do not understand why the Commission did so. It did not explain why it rejected Mountain's contention that the originating carrier should be charged all of the costs. In any event, by indicating that Mountain could charge the originating carrier, it suggested that Mountain was essentially correct in claiming that the originating carrier should bear <u>all</u> the transport costs.

<u>Id.</u> at 649 (emphasis in original).

Again, this holding reinforces the conclusion that the originating ILEC bears the transit fees responsibility without exception, and that the Commission cannot lawfully condition the CMRS carriers' right to avoid these costs on their applying for and proving a right to asymmetrical reciprocal compensation rates.

The majority attempts to support its "single POI" determination by recitation to "equities." In my view, the outcome of this case is dictated by controlling federal precedent, which requires a determination different from that reached in the majority opinion. Nonetheless, reduced to their essence, the cited equities are that the RLECs are severally disadvantaged under a reciprocal compensation scheme where each carrier bears the transit charges on its originated traffic; RLECs are small and without bargaining power, etc. These might be compelling reasons for shielding these carriers from competition or for maintaining their rural exemption or for refusing to require them to incur the costs of full blown TELRIC costs studies. However, such determinations are not the issues here. Many of the "equities" find no support in the record (the CMRSs have been dumping traffic or the RLECs), are new ones for which the CMRS carriers have had no opportunity to address (use of a single POI places the RLECs in the position they would have been in had they been able to rely on Section 251(c)(2). FCC rulings requiring ILECs to initiate arbitrations are quirky and peculiar, and place RLECs in disadvantageous positions) or are logically unpersuasive (the transit fees are too high because the RLECs did not negotiate them.) The CMRS carriers pay the vast majority of these fees because most of the traffic originates on their system, so they have greater incentive to keep them low than the RLECs do. The new "equities", after all, are now substituted for the original one in the RAO that RLEC payment of the transit fees would cripple them financially, which the CMRS carriers successfully debunked in the post hearing filings.

/s/ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

DOCKET NO. P-21, SUB 71
DOCKET NO. P-35, SUB 107
DOCKET NO. P-61, SUB 95

Commissioner Lorinzo L. Joyner, dissenting in part:

I respectfully dissent from Majority's Findings of Fact Nos. 1 and 2 and its resolution of Matrix Issues 1 and 4. As to those, I agree with the conclusions, legal rationale and analysis articulated by Chairman Finley in his Dissent. As to all other issues in dispute, I concur with the result reached by the Majority.

I write separately to emphasize my view that Commission discretion should not trump persuasive federal authority in arbitrations such as this. In these cases, the Commission sits as an arbitrator of matters arising under federal law, and its decisions in reference thereto are subject to review by the federal courts. I do not believe that the Majority has given due deference to controlling federal precedents that are inconsistent with the result it was determined to be just.

The Majority decision appears to be "result" driven. The Order struggles to affirm the panel's resolution of these issues in its December 20, 2007 RAO; a result that was, in fact, based on a unanimous panel decision issued on October 8, 2004, in Docket No. P-118, Sub 130. The Majority now concedes that the legal justification of the panel's decision in its December 20, 2007 RAO was fatally flawed, in that Section 251(c)(2)(B) of the Telecommunications Act of 1996 was not determinative of the location of the point of interconnection. In lieu of re-examining its 2004 decision, the Commission, "in the exercise of its sound discretion," found an alternative basis on which to reaffirm the one-POI decision originally adopted by a majority of the panel in this case, all the while attempting to distinguish away, or simply ignore, pronouncements by several federal courts that do not support the result it determined to be appropriate – a result that appears to be based principally upon equitable considerations.

I value existing Commission precedent and the regulatory certainty that adherence to such precedents provides. I do not think it wise policy for the Commission to depart from its precedents unadvisedly. There are instances, however, when it is appropriate for the Commission to reexamine its prior holdings, if justified by the law and controlling authorities, and supported by the evidence. I think this case presented just such an opportunity, notwithstanding the equities -- real or imagined.

/s/ Lorinzo L. Joyner
Commissioner Lorinzo L. Joyner

Appendix A
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RLECs/CMRS Providers Arbitration Proceeding
Docket No. P-21, Sub 71
Docket No. P-35, Sub 107
Docket No. P-61, Sub 95

Act	Telecommunications Act of 1996
ALLTEL	ALLTEL Communications, Inc.
ARMIS	Automated Reporting Management Information System
AT&T	BellSouth Telecommunications, Inc., d/b/a AT&T North Carolina
Cingular	New Cingular Wireless, LLC, d/b/a Cingular Wireless
CLEC	Competitive Local Exchange Company (Carrier)
CLP	Competing Local Provider
CMRS	Commercial Mobile Radio Service
CMRS Providers	ALLTEL and Cingular
Commission	North Carolina Utilities Commission
CPR	Continuing Property Record
CTIA	Cellular Telecommunications and Internet Association
DLC	Digital Loop Carrier
Ellerbe	Ellerbe Telephone Company
FCC	Federal Communications Commission
HAI	The Hatfield Model
ICOs	Independent Telephone Companies
ILEC	Incumbent Local Exchange Company (Carrier)
IXC	Interexchange Carrier
LATA	Local Access and Transport Area
LSS	Local Switching Support
MAG Plan	Multi-Association Group Plan
MebTel	MebTel, Inc.
MOU	Minute of Use
MTA	Major Trading Area
NECA	National Exchange Carriers Association
NPRM	Notice of Proposed Rulemaking
POI	Point of Interconnection
Public Staff	Public Staff – North Carolina Utilities Commission
Randolph	Randolph Telephone Company
RAO	Recommended Arbitration Order

Appendix A
Page 2 of 2

RBOC	Regional Bell Operating Company
RLECs	Rural Local Exchange Companies – i.e., Ellerbe, MebTel, and Randolph
Sprint PCS	Sprint Spectrum LP, as an agent for SprintCom, Inc., d/b/a Sprint PCS
SunCom	SunCom Wireless Operating Company, LLC
TA96	Telecommunications Act of 1996
TELRIC	Total Element Long Run Incremental Cost
UNE	Unbundled Network Element
UNE-P	Unbundled Network Element – Platform

DOCKET NO. P-42, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Petition of North State Telephone Company, d/b/a)
North State Communications for) ORDER APPROVING
Approval of a Modified Price Regulation Plan) MODIFIED PRICE
Pursuant to G.S. 62-133.5(c)) REGULATION PLAN

BY THE COMMISSION: G.S. 62-133.5(a) provides that "[a]ny local exchange company [LEC], subject to the provisions of G.S. 62-110(f1), that is subject to rate of return regulation pursuant to G.S. 62-133 . . . may elect to have rates, terms and conditions of its services determined pursuant to a form of price regulation, rather than rate of return or other forms of earnings regulation."

Under the form of price regulation authorized by G.S. 62-133.5(a), "the Commission shall, among other things, permit the local exchange company to determine and set its own depreciation rates, to rebalance its rates, and to adjust its prices in the aggregate, or to adjust its prices for various aggregated categories of services, based upon changes in generally accepted indices of prices."

North State Telephone Company, d/b/a North State Communications (North State) is currently operating under a price regulation plan that was approved by the Commission pursuant to G.S. 62-133.5(a) in August 2002 and bears an effective date of December 11, 2002.

G.S. 62-133.5(c) states that any LEC subject to price regulation under the provisions of subsection (a) of G.S. 62-133.5 may file an application with the Commission to modify such form of price regulation. The statute requires the Commission to approve a modified price regulation plan for a LEC upon finding that a proposed plan:

(i) protects the affordability of basic local exchange service, as such service is defined by the Commission;

(ii) reasonably assures the continuation of basic local exchange service that meets reasonable service standards established by the Commission;

(iii) will not unreasonably prejudice any class of telephone customers, including telecommunications companies; and

(iv) is otherwise consistent with the public interest.

Further, G.S. 62-133.5(c) provides that, if the Commission disapproves, in whole or in part, a LEC's application to modify its existing form of price regulation, the Company may elect to continue to operate under its then existing plan previously approved under G.S. 62-133(a) or G.S. 62-133.5(c).

On April 4, 2008, North State filed a Petition seeking modifications to its original and current price regulation plan along with prefiled testimony and exhibits.

On July 8, 2008, North State and the Public Staff filed a proposed order scheduling a hearing and requiring a public notice and the filing of prefiled testimony.

On July 14, 2008, the Commission issued its *Order Scheduling Hearing, Requiring Public Notice, and Requiring Prefiled Testimony.* The Commission scheduled a public hearing for September 18, 2008 to be held in High Point and an evidentiary hearing for September 24, 2008 to be held in Raleigh. The Order also established a schedule for the filing of direct testimony and rebuttal testimony.

On September 3, 2008, the Public Staff and North State filed a Joint Motion to Cancel Evidentiary Hearing and Decide Matter Based on Paper Filings.

On September 5, 2008, in response to the Joint Motion, the Commission issued its *Order Canceling Evidentiary Hearing and Authorizing Further Filings.* In its Order, the Commission canceled the evidentiary hearing, relieved the parties of any further obligations regarding prefiled testimony, and allowed the parties to file their agreement on price plan modifications as well as comments and supporting affidavits on any unresolved issues no later than October 1, 2008. The Commission noted that the public hearing would take place as previously scheduled.

The public hearing was held as scheduled on September 18, 2008 in High Point before Hearing Examiner Daniel Long. No public witnesses appeared at the hearing; however, representatives for both North State and the Public Staff were in attendance.

On October 1, 2008, North State and the Public Staff filed their Stipulation and Agreement and requested that the Commission approve the Stipulated Price Regulation Plan and allow North State to implement the Stipulated Plan effective October 31, 2008. Also on October 1, 2008, the Public Staff filed the affidavits of Robert A. Goetz, Engineer, Public Staff Communications Division, and Charles B. Moye, Engineer, Public Staff Communications Division. North State filed the Supplemental Testimony of Mark Dula on the same date. The October 1, 2008 filings indicated that the parties had reached agreement on all aspects of a modified price regulation plan for North State except for one discrete issue. The Public Staff proposed the inclusion of two service quality measures in Section 11 – Service Measurements of the new price regulation plan (specifically, Business Office Answertime and Repair Service Answertime) while North State opposed the Public Staff's recommendation in this regard.

In his Supplemental Testimony filed on October 1, 2008, Mr. Dula described what occurred in this proceeding after the filing of North State's proposed revisions to its price regulation plan. He noted that, on June 19, 2008, the Public Staff - Communications Division presented North State with proposed modifications to North State's filed Revised Plan and explained that the suggested changes would provide the Public Staff and the Commission assurance that local ratepayers remain protected. Mr. Dula stated that North State reviewed the proposed changes and opened a dialog with the Public Staff. He maintained that several subsequent meetings were held between North State and the Public Staff in an effort to reach agreement concerning mutually acceptable alterations to North State's price regulation plan. Mr. Dula asserted that the negotiations between the parties were productive and that settlement was reached on several outstanding issues, eliminating the need for a contentious evidentiary hearing.

As described in the affidavit of Mr. Moye and the Stipulated Plan itself, the Stipulated Plan provides for the following:

- Classification of existing services into three categories of service designated as Moderate Pricing Flexibility Services, Interim Competitive Services, and Total Pricing Flexibility Services. The current plan has four categories, including Basic Services, Interconnection Services, Non-Basic 1 Services, and Non-Basic 2 Services.

- The Offset will be set to zero percent. In the current plan, the Offset is set at 2%.

- Services that would be classified in the Moderate Pricing Flexibility Services category include business and residential basic local exchange services and switched access charges applicable to interexchange carriers. Prices for individual rate elements associated with these services could be increased by a maximum of 10% in each Plan year, provided that revenues for the category do not increase by more than one and one-half times the rate of inflation minus the Offset, which is set at zero percent.

- The Interim Competitive Services category has no revenue constraint and individual rate elements in this category may increase by no more than 15% during a plan year.

- The Total Pricing Flexibility Services category has no revenue constraint and individual rate elements in this category have no rate element constraint.

- The Stipulated Plan will allow all current and future services within the Interim Competitive Services category and the Total Pricing Flexibility Services category to be detariffed. Tariffs for services currently assigned to those service categories as of the effective date of the modified plan will be withdrawn once appropriate notice has been provided to all impacted customers. However, there is no change in the requirement for

North State to notify customers of rate increases at least 14 days in advance, so that part of the customer protection built into the current plan is still intact.

- The Stipulated Plan allows North State to rebalance Expanded Local Calling Area (ELCA) service within the Moderate Pricing Flexibility Services category without the resulting increases being subject to the normal operation of the rate element constraint. The only restriction is that the impact on individual line residential or individual line business customers during any plan year may not exceed $4.00 or $6.00, respectively.

- A number of services are transferred in the Stipulated Plan to service categories that have minimal or no rate element or service category revenue constraints. However, the Stipulated Plan provides that if changes in the competitive market raise concerns regarding whether a service should remain in a less restrictive service category, the Commission may re-evaluate the appropriateness of the current service category assignment. Specifically, it allows the Commission, upon petition of any interested party and in reaction to changes in the competitive environment, customer complaints, or action by North State, to reassign services from the Interim Competitive Services category and the Total Pricing Flexibility Services category to another service category. In addition, the Stipulated Plan allows the Commission to determine whether the service should be reassigned to the new service category at its current rate, or at any rate in effect up to one year prior to the time the petition was filed.

- The Stipulated Plan allows North State to increase rates by a set amount regardless of the applicable rate element constraint. Specifically, for services in the Moderate Pricing Flexibility Services category, a rate element priced on a flat-rated monthly basis would be allowed a rate increase of 10% or $0.35, whichever is greater. A rate element priced on a per use basis would be allowed a rate increase of 10% or $0.15, whichever is greater. A similar constraint is available for rate elements in the Interim Competitive Services category, with the following allowed minimum rate increases: 15% or $0.50, whichever is greater, for rate elements priced on a flat-rated monthly basis, and 15% or $0.30, whichever is greater, for rate elements priced on a per use basis. There are two exceptions to the per use minimum rates: (1) minute of use rates, such as usage rates associated with expanded local calling plans, can be increased by a maximum of $0.01 or the rate element constraint, whichever is greater, and (2) this provision will not apply to Intrastate Switched Access Service rates.

- North State will be allowed to propose multiple rate increases per year for individual rate elements, provided the cumulative price increase remains within the appropriate rate element constraint. Currently, North State is allowed to increase the price of any individual rate element only once per year.

- The Stipulated Plan retains language prohibiting North State from operating in an anticompetitive manner, and prohibits unlawful price discrimination, predatory pricing, price squeezing, or anticompetitive bundling or tying arrangements. In addition, under the language of the Stipulated Plan, the Commission retains oversight for service quality, complaint resolution, and compliance by North State with all elements of the plan.

- The Stipulated Plan continues to provide for financial penalties to be paid to customers if North State fails to meet service objectives established by the Commission. North State and the Public Staff are in disagreement whether the Business Office Answertime objective and the Repair Service Answertime objective should be added to the price plan, with the Public Staff supporting their inclusion and North State opposing the inclusion of these two objectives.

WHEREUPON, based on the foregoing and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. North State is a "local exchange company" as the term is defined in G.S. 62-3(16a). North State currently operates under a price regulation plan approved by the Commission in August 2002 pursuant to G.S. 62-133.5. North State is seeking modifications to its price regulation plan pursuant to G.S. 62-133.5(c). Thus, this matter is properly before the Commission for consideration, and North State meets all of the requirements for price regulation under G.S. 62-133.5.

2. The Stipulated Plan will protect the affordability of basic local exchange service.

3. The Stipulated Plan will reasonably assure the continuation of basic local exchange service that meets reasonable service standards.

4. The Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

5. The Stipulated Plan is otherwise consistent with the public interest.

6. North State should not, at this time, be required to include Business Office Answertime and Repair Service Answertime measures in Section 11 of its modified price regulation plan.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 1

Finding of Fact and Conclusion of Law No. 1 is supported by the record as a whole and is not contested.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 2
AFFORDABILITY

Finding of Fact and Conclusion of Law No. 2 (and Nos. 3-5 as well) are supported by the affidavit of Mr. Moye and testimony of North State witness Dula.

Mr. Moye stated in his affidavit that, in his opinion, the Stipulated Plan protects the affordability of basic local exchange service. He noted that the existing rates for services offered by North State will be the rates the Company will continue to offer under the Stipulated Plan.

Mr. Moye stated that those rates have been approved under the statutory mechanism applicable to companies operating under price regulation and are considered just and reasonable. Mr. Moye maintained that basic local exchange service rates will be protected from unreasonable future price increases by being assigned to the Moderate Pricing Flexibility Services category, which is the most restrictive category in the Stipulated Plan. Mr. Moye noted that North State will continue to offer Lifeline and Link-Up service, which provides targeted assistance to low-income households, helping to make basic local exchange service more affordable.

In Commission Rule R17-1(a), the Commission has defined basic local exchange service as "[t]he telephone service comprised of an access line, dial tone, the availability of touchtone, and usage provided to the premises of residential customers or business customers within a local exchange area." In the Stipulated Plan, basic local exchange service is included in the Moderate Pricing Flexibility Services category, which allows North State some flexibility to adjust the price of basic local exchange service. Under the Stipulated Plan, aggregate annual price changes for services included in the Moderate Pricing Flexibility Services category are limited to one and one half times the rate of inflation as measured by the annual change in the Gross Domestic Product Price Index (GDPPI), minus an offset of zero percent.

Further, under the Stipulated Plan, the rate element constraint is 10% in the Moderate Pricing Flexibility Service category. In the Interim Competitive Services category the rate element constraint is 15%. The Stipulated Plan also includes a provision under which any rate element in the Moderate Pricing Flexibility Services category may be increased on an annual basis by up to ten percent (10%) or thirty-five cents ($0.35), whichever is greater, if it is priced on a flat-rated monthly basis, and up to ten percent (10%) or fifteen cents ($0.15), whichever is greater, if it is priced on a per use basis. A similar constraint is available for rate elements in the Interim Competitive Services category, with the following allowed rate increases: up to fifteen percent (15%) or fifty cents ($0.50), whichever is greater, for rate elements priced on a flat-rated monthly basis, and up to fifteen percent (15%) or thirty cents ($.30), whichever is greater, for rate elements priced on a per use basis. Exceptions to this provision are: (1) minute-of-use rates, such as usage rates associated with ELCA service, can be increased by a maximum of $0.01 or the rate element constraint, whichever is greater; and (2) this provision does not apply to Intrastate Switched Access Service rates.

The Commission concludes that the incremental increase in pricing flexibility allowed by the Stipulated Plan is appropriate and still protects the affordability of basic local exchange service. Prices for Moderate Pricing Flexibility Services in the aggregate can increase by no more than one and one half times the change in GDPPI. However, after reviewing the Stipulated Plan, the Commission believes additional language needs to be added to Section 6.A(1) to more clearly note this fact. Therefore, the Commission finds that the following should be added to Section 6.A(1) of the Stipulated Plan:

> This Plan establishes a pricing structure that allows the Company to adjust its prices for rate elements included in all service categories. <u>Aggregate revenues in the Moderate Pricing Flexibility Services category can increase by 1.5 times inflation, as measured by the increase in the GDPPI, minus the Offset. There are no category revenue constraints for the Interim Competitive Services category and</u>

the Total Pricing Flexibility Services category. (Underlining represents additional language to be added to the Stipulated Plan.)

Further, the Commission notes that aggregate price increases for rate elements in the Moderate Pricing Flexibility Services category above the constraint must be accompanied by commensurate (offsetting) aggregate price reductions in other rate elements. The Stipulated Plan further protects the affordability of local exchange services by generally limiting the potential annual price increase for any single rate element to 10% for services in the Moderate Pricing Flexibility category.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 3
SERVICE QUALITY

The Stipulated Plan retains provisions expressly relating to service quality measurements and the provision for appropriate service quality penalties. The Commission retains powers and authority with regard to the provision of quality service. North State will continue to operate under Commission Rule R9-8 and will be subject to the service quality penalties set forth in the Stipulated Plan. Furthermore, the Commission will retain oversight for service quality, complaint resolution, and compliance with all elements of the Stipulated Plan and applicable state law.

Thus, the Commission concludes that the Stipulated Plan reasonably assures the continuation of basic local exchange service that meets the reasonable service standards established by the Commission in Commission Rule R9-8.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 4
NO PREJUDICE AMONG CUSTOMER CLASSES

Mr. Moye stated in his affidavit that, under the Stipulated Plan, no class of telephone customers, including telecommunications companies, will be unreasonably prejudiced. Mr. Moye noted that the Stipulated Plan requires that the price of any individual rate element for any service offered by North State shall be equal to, or in excess of, its Long Run Incremental Cost, unless: (1) exempted by the Commission, or (2) required to meet the offering of a competitor. Mr. Moye maintained that the Stipulated Plan provides that North State will not "engage in predatory pricing, price squeezing, price discrimination, or anticompetitive bundling or tying arrangements." Mr. Moye noted that the Stipulated Plan also provides that North State will not "give any unreasonable or unlawful preference or advantage to the competitive services of affiliated entities." Mr. Moye asserted that the Stipulated Plan provides that the Commission will retain "oversight for service quality, complaint resolution, and compliance by the Company with all elements of this Plan." Mr. Moye opined that further protection is afforded by the fact that the terms and conditions of service offerings will remain as they are today and any change will be subject to review by the Commission. Mr. Moye noted that the Stipulated Plan also provides that the "Commission may on its own motion, or in response to a petition from any interested party, investigate whether a tariff is consistent with this Plan and the Commission's rules."[1]

The Commission finds the record to be persuasive and concludes that the Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 5
PUBLIC INTEREST STANDARD

Mr. Moye asserted in his affidavit that the Stipulated Plan is in the public interest for a number of reasons. Mr. Moye noted that the Stipulated Plan will allow North State to structure its services and rates in order to serve the increasingly competitive telecommunications market. He stated that the service category revenue constraints and rate element constraints incorporated in the Stipulated Plan will continue to moderate excessive rate increases, and the continuing transition to a competitive marketplace should offer customers an increasing array of telecommunications services at competitive prices. Mr. Moye maintained that the service quality objectives, self-enforcing penalties, and Commission authority over complaint resolution will help to ensure that North State continues to provide a high level of service to its customers. Mr. Moye opined that, in addition to these benefits and protections, the Stipulated Plan offers North State increased flexibility to tailor its service offerings to satisfy current customer expectations and to provide new enhanced features and services in the future.

The public interest standard is one the Commission has employed in its deliberations for many years. The Commission finds the Stipulated Plan to be in the public interest for several reasons. First, it permits the rate rebalancing necessary for the ongoing transition to competition, without allowing the rebalancing process to proceed at such a rapid pace as to impose an undue burden upon those customers whose rates may increase. Second, the Stipulated Plan provides affordable rates and assures that North State will continue to provide adequate service to its customers. Third, the Stipulated Plan contains specific service performance measures and penalties. Fourth, the Commission believes that a competitive marketplace is consistent with the goals established by the legislature, and will engender significant benefits for the citizens of the State through improved services, generally lower prices, and greater technological innovation, and that it will therefore offer significant potential for enhanced economic development. And, finally, the Commission notes that the Stipulated Plan contains a provision in Section 4.C(1) which states that, "[u]pon petition by any interested party, and in reaction to changes in the competitive environment, customer complaints, or action by the Company, the Commission has the authority to reassign services from the Interim Competitive and Total Pricing Flexibility Services categories to another service category." The Commission finds this provision to further support its conclusion that the Stipulated Plan is in the public interest.

At the same time, the Commission recognizes that the public interest could be adversely affected if telecommunications services were fully deregulated, or regulated so lightly that the only limitations on prices were those imposed by competition at a time when competition has

[1] The Commission notes that, under the Stipulated Plan, all current and future services within the Interim Competitive Services category and the Total Pricing Flexibility Services category will be detariffed.

not yet progressed to the point where it could discipline prices effectively in North State's service territory.

In addressing this concern, the Commission notes that there is a close correlation between the assignment of telecommunications services to pricing categories under the Stipulated Plan and the degree of competition for particular services in North State's service area. The assignment of services to categories in the Stipulated Plan was determined by negotiation between North State and the Public Staff; however, the services assigned to the Total Pricing Flexibility Services category are those for which the greatest degree of competition exists. In contrast, the services categorized as Moderate Pricing Flexibility Services are those for which competition is less vigorous. The Commission finds it significant that the Public Staff, which is responsible under G.S. 62-15 for protecting the interests of the using and consuming public, has been willing to agree to the Stipulated Plan. Under the Stipulated Plan, the Commission will retain sufficient authority to monitor and maintain service quality, to review rate structures and the terms and conditions of tariffs against a public interest standard, to decide complaints concerning anticompetitive behavior, and to oversee the reclassification and regrouping of services and the financial impacts of governmental actions.

In addition, the Commission notes that no public witnesses testified in opposition to the Stipulated Plan.

Accordingly, the Commission concludes that the provisions of the Stipulated Plan are sufficiently limited, and that the Stipulated Plan is consistent with the public interest given the current level of competition in North State's service territory. Furthermore, the Commission recognizes that, under the Stipulated Plan, it retains regulatory oversight authority over any request by North State to classify new services or reclassify existing services to a Category providing greater pricing flexibility. This continuing authority regarding the appropriate classification of services is important, as it enables the Commission going forward to ensure that each request to classify or reclassify services is supported by a showing of increased competition for these services.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 6 INCLUSION OF TWO SERVICE STANDARDS

North State presented its position on this issue in the Supplemental Direct testimony of Mark Dula, and the Public Staff presented its position on this issue in the affidavit of Robert A. Goetz.

Mr. Dula explained that the Public Staff and North State were able to reach a resolution on all outstanding issues except one. Mr. Dula noted that that issue is the relative need to include Business Office and Repair Service answertime constraints under the service quality penalty provisions in the modified price regulation plan. Mr. Dula maintained that the Public Staff desires North State to include Business Office and Repair Service answertime measurements in the service quality penalty provision section of the Stipulated Plan. He noted that these two answertime measures would be in addition to the eight service quality measures that North State agrees to continue to include in the service quality section of the Stipulated Plan and which are (and will remain) subject to performance penalties.

Mr. Dula asserted that North State does not believe that there is any reasonable need for Business Office and Repair Service answertime measurements to be included in North State's modified price regulation plan. He noted that there are several reasons why North State believes that these answertime measures are not needed in the modified price regulation plan.

Mr. Dula maintained that the primary purpose underlying North State's proposal to restructure its price plan earlier this year was a desire to reduce unnecessary regulatory constraints and administrative burdens in order to allow the Company to compete more effectively in a highly contested telecommunications market. Mr. Dula stated that the Commission has recognized in past price plan proceedings that increased market competition merits decreasing regulatory oversight, not the addition of more oversight. Mr. Dula also noted that the Commission, in its Order dated April 14, 2008 approving a modified price regulation plan for AT&T, relaxed the service quality requirements on AT&T by suspending the penalty provision contained in AT&T's price plan. He noted that the Commission reasoned that, "AT&T should be rewarded for this marked improvement in service quality" and "compliance has also likely improved because of the demands of the competitive marketplace as well as AT&T's commitment to excellence." Mr. Dula asserted that North State has consistently met the same service quality measures discussed in AT&T's case, operates in a comparable competitive marketplace and has no lesser commitment to excellence than AT&T. Mr. Dula noted that North State is not asking for a waiver of the existing service quality requirements; instead, North State is simply asking that unnecessary additional regulatory burdens not be placed on it. Mr. Dula further maintained that North State will continue to be subject to Commission Rule R9-8's reporting requirements, which include Business Office and Repair Service Answertimes. He noted that all service metrics are available for public view via the Commission's website incenting North State to consistently maintain a passing grade. Mr. Dula next stated that North State's track record does not indicate any need for additional oversight. He noted that North State has never been required to pay penalties for poor service performance related to the eight measures included in its price regulation plan. Mr. Dula maintained that, during the same time period, North State's Business Office and Repair Service Answertimes have consistently met, by a wide margin, the 30 seconds metric. He noted that North State's range for all months during 2007 and 2008 for the combined answertime measures falls between 8 seconds and 18 seconds, well below the 30 second standard. Mr. Dula also asserted that North State's competitors are subject to none of these service quality penalty requirements, and that placing additional burdens on North State only achieves migration away from a level regulatory playing field rather than narrowing the gap. Mr. Dula finally opined that North State's existing price regulation plan met the standards listed in G.S. 62-133.5 when the Commission approved the plan in 2002 and that plan contained no penalty provisions for Business Office and Repair Service Answertimes. He asserted that North State's modified price regulation plan meets those same standards without the addition of these service measures.

Mr. Goetz, with the Communications Division of the Public Staff, maintained in his affidavit that he has examined the petition of North State and the associated testimony, filed on April 4, 2008, in this docket, seeking revision of the Company's approved price regulation plan.

He noted that North State proposes to retain the eight service objectives listed in Section 12 of its existing plan, which excludes Business Office and Repair Service Answertimes. Mr. Goetz asserted that the Public Staff believes that Business Office and Repair Service Answertimes (Measures 7 and 8 of Rule R9-8) should be incorporated into North State's modified price plan.

Mr. Goetz stated that the Public Staff and the Commission maintain historical records of North State's Business Office and Repair Service Answertime performance for at least the months from February 2001 through June 2008. He asserted that these records should assist the Commission in evaluating North State's past and present performance on these two objectives and its ability to continue that level of performance.

Mr. Goetz noted that, prior to July 2004, the Rule R9-8 benchmark for Business Office and Repair Service Answertime was "90% or more of calls answered within 20 seconds or an EAA (Equivalent Average Answertime) in seconds." He stated that on June 4, 2004, the Commission issued an Order increasing the benchmark for both objectives to 30 seconds. Mr. Goetz noted that the Commission concluded that the new 30 second benchmark, which was more than double the previous benchmark, was "entirely reasonable and appropriate."

Mr. Goetz maintained that North State witness Dula, on page 7 of his prefiled testimony, stated that "North State has consistently exceeded additional service quality measures, Business Office and Repair answertimes, included in NCUC Rule R9-8 but excluded from the service quality section of the Plan." Mr. Goetz noted that his review of North State's quarterly service quality reports for July 1, 2004 through June 20, 2008 supports Mr. Dula's statement. Mr. Goetz stated that, during this period, North State consistently met the 30 second ASA requirement for Business Office and Repair Service calls. Mr. Goetz maintained that Mr. Dula further stated that, "[b]ased on this performance, it is evident that North State's Plan has met the requirement that it 'reasonably assures the continuation of basic local exchange service that meets reasonable service standards.'"

Mr. Goetz stated that he agrees that North State has met and should continue to have the capability to meet the Commission's reasonable and appropriate requirements for Business Office and Repair Service answertimes. He asserted that he believes that North State will be more likely to continue its current satisfactory performance in meeting the Commission's objectives if the Business Office and Repair Service answertime requirements of Rule R9-8 are made part of the modified price plan than it will be if they continue to be left out of it.

Mr. Goetz further noted that the Commission has approved eight different price regulation plans that cover twelve separate local exchange companies. He maintained that three price plans (AT&T North Carolina, Inc., Carolina Telephone and Telegraph Company and Central Telephone Company, and North State Telephone Company) have never been subject to any price plan penalty provisions concerning their Business Office or Repair Service answertime performance. Mr. Goetz stated that the other current price regulation plans (Barnardsville Telephone Company, Mebtel, Inc., Randolph Telephone Company, and Saluda Mountain Telephone Company; Service Telephone Company; Verizon South, Inc.; Windstream Concord Telephone Company; and Windstream North Carolina, Inc.) include provisions that make them subject to self-enforcing penalties if they fail to meet the Rule R9-8 benchmark for Business Office and Repair Service answertimes.

Mr. Goetz maintained that North State has been meeting the Commission's 30 second ASA benchmark for Business Office and Repair Service answertimes since its inception in July 2004, has the capability to continue meeting this requirement, and had not shown good cause for exclusion from the requirement. Mr. Goetz recommended that the Commission require North State to incorporate these two Rule R9-8 objectives into its modified price plan and make them subject to the same penalty provisions prescribed for the other eight objectives.

The Commission does not find good cause to include the Business Office Answertime or Repair Service Answertime objectives in Section 11 of North State's modified price regulation plan at this time. Nevertheless, the Commission believes it is important to retain the right, pursuant to G.S. 62-80, to reconsider this decision should North State fail to continue to consistently meet the service quality objectives in question. Therefore, the Commission's decision with regard to excluding the Business Office Answertime measurement and the Repair Service Answertime measurement from the penalties provision of the modified price regulation plan is contingent on North State's agreement to an indefinite waiver of the ratchet provision found in G.S. 62-133.5(c).

The Commission notes that these measures were not included in North State's original price regulation plan which was adopted in 2002. Clearly, competition has done nothing but increase since that time, and with increased competition comes the recognition that the competitive marketplace takes on greater and greater significance in the operation of the Company, i.e., competition takes on a greater role while regulation by this Commission takes on a lesser role in the operation of a Company subject to competition. Further, it is undisputed that North State has consistently met the objectives for these two measures since at least July 2004, which is more than four years ago. The Commission does not believe that the inclusion of these two measures at this time would provide any greater guarantee that North State will continue to meet these objectives since, obviously, something other than the threat of monetary penalties has ensured for the past several years that North State met the objectives for Business Office Answertime and Repair Service Answertime.

Accordingly, the Commission will not, at this time, require North State to include the Business Office Answertime objective and the Repair Service Answertime objective in the Company's modified price regulation plan.

FINAL OBSERVATIONS AND CONCLUSIONS

Consistent with the law and policy of this State, North State and the Public Staff have negotiated a Stipulated Plan that meets each of the criteria prescribed by G.S. 62-133.5(c) and therefore the Commission finds that approval of the Stipulated Plan is appropriate. The Commission has approved similar price plans for similarly situated companies. The Stipulated Plan in this case has many elements in common with these previously approved price regulation plans. The record shows that the competitive landscape has changed considerably since 2002, when North State's original price regulation plan was approved. The Commission believes that the flexibility afforded by the Stipulated Plan will enable North State to compete effectively and continue to provide reasonably affordable basic local exchange service. The Commission's decision to approve the Stipulated Plan is based upon its analysis of the record in this proceeding and should not be understood as indicating that a different plan would not be appropriate given the existence of a different record.

IT IS, THEREFORE, ORDERED that the Stipulated Plan be, and the same is hereby, approved for implementation by North State effective October 31, 2008, provided that North State shall, not later than November 5, 2008, refile the Stipulated Plan reflecting: (1) the Commission's decision to exclude the two service quality measurements in dispute contingent on North State's agreement to an indefinite wavier of the ratchet provision found in G.S. 62-133.5(c); and (2) the additional language required to be included in Section 6.A(1). North State shall also explicitly indicate its willingness to indefinitely waive the ratchet provision of G.S. 62-133.5(c) with respect to the two service quality measurements in dispute between North State and the Public Staff.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of October, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Owens and Commissioner Lee did not participate in this decision.

bp102908.01

DOCKET NO. P-55, SUB 1013

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of AT&T North Carolina for Further	)	ORDER AUTHORIZING
Detariffing of Services and Modifications to Its	)	MODIFIED PRICE
Price Plan	)	REGULATION PLAN

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; and Commissioners Robert V. Owens, Jr., Sam J. Ervin, IV, James Y. Kerr, II, Howard N. Lee, and William T. Culpepper, III

BY THE COMMISSION: This matter arose on April 23, 2007, upon the filing of a Petition for Further Detariffing of Services and Modifications to Its Presently Approved Price Plan Pursuant to G.S. 62-133.5(c) by AT&T North Carolina (AT&T).

BACKGROUND

On May 2, 2007, the Commission issued an *Order on Procedure* wherein the Commission established a schedule for comments and affidavits to be filed, set a date for Proposed Orders and/or Briefs to be filed, and provided instructions on a public notice.

AT&T filed a proposed Public Notice on May 11, 2007, and subsequently, on May 14, 2007, a proposed revised Public Notice. The revised Public Notice reflected further consultations with the Public Staff.

By Order dated May 16, 2007, the Commission approved the revised Public Notice and ordered that said Public Notice be published in the newspapers outlined by AT&T according to AT&T's proposed schedule.

On June 6, 2007, AT&T and the Public Staff filed a Joint Motion for Extension of Time wherein the Parties requested that the Commission extend the deadline for the Public Staff and other intervenors to file comments and affidavits in this proceeding until further notice. The Commission granted the Petition by Order dated June 8, 2007.

On June 7, 2007, Verizon South Inc. (Verizon) filed comments in support of AT&T's Petition.

On June 8, 2007, the Department of Defense and All Other Federal Executive Agencies (DOD/FEA) filed initial comments on AT&T's Petition.

On June 20, 2007, AT&T filed revisions to its Petition, the supplemental affidavit of Ms. Harrison, and a replacement Harrison Exhibit 1.

Also on June 20, 2007, AT&T and the Public Staff filed a Joint Motion for a New Procedural Schedule. AT&T and the Public Staff presented proposed dates for initial comments, responsive comments, supplemental affidavits, further comments, final comments, and Proposed Orders and/or Briefs. By Order dated June 22, 2007, the Commission granted the Joint Motion and approved the modified schedule as proposed by AT&T and the Public Staff.

On June 29, 2007, the Public Staff filed its initial comments along with the affidavits and exhibits of Millard N. Carpenter, III and John T. Garrison, Jr. Also on June 29, 2007, the Attorney General filed his initial comments on AT&T's Petition.

On July 2, 2007, after being granted an extension of time to file, the Public Staff filed the affidavit and exhibits of Robert A. Goetz.

On July 20, 2007, the Public Staff filed a revised copy of Carpenter Exhibit 6, which corrected four incorrect entries on the Exhibit.

On July 27, 2007, AT&T filed its Responsive Comments, along with the Supplemental Affidavits and Exhibits of Ms. Harrison, Mr. Shooshan, and Mr. Smith.

On August 17, 2007, further Comments were filed by the DOD/FEA and the Public Staff.

On August 31, 2007, AT&T filed its Final Comments.

On September 12, 2007, the Commission issued its *Order Scheduling Oral Argument* in this proceeding. The Commission scheduled the Oral Argument to be held on November 5, 2007.

On October 5, 2007, Briefs were filed by AT&T, the Attorney General, and the DOD/FEA. The Public Staff filed a Proposed Order on October 5, 2007.

On November 1, 2007, the Public Staff filed a Motion to Reschedule Oral Argument. By Order dated November 2, 2007, the Commission rescheduled the Oral Argument for Tuesday, November 27, 2007.

By Order dated November 21, 2007, the Commission instructed AT&T to file responses to four specific requests for additional information.

The Oral Argument was held as scheduled on November 27, 2007.

On December 10, 2007, AT&T filed the information requested in the *November 21, 2007 Order*. AT&T further submitted a late-filed exhibit requested by the Commission during the oral argument that reflects prices for competitive alternatives to AT&T's local exchange service. Finally, AT&T filed a proposed revised price regulation plan permitting the Commission to rescind its approval of the changes contained in the proposed plan after AT&T provides a competitive marketplace update to the Commission in 2010. AT&T requested that the Commission substitute the proposed plan filed on December 10, 2007 for the plan identified as Exhibit 3 to Mr. Smith's affidavit.

On December 13, 2007, the Commission issued an Order soliciting comments on AT&T's December 10, 2007 data and proposed revised price regulation plan by no later than January 14, 2008. That Order further provided that AT&T file reply comments no later than January 28, 2008.

Initial comments on the proposed revised plan were filed by the Attorney General, the DOD/FEA, and the Public Staff on January 14, 2008. AT&T filed its reply comments on January 28, 2008.

AT&T'S PETITION

AT&T stated that it is asking the Commission to take one more step toward further modernization of the regulatory framework governing AT&T's operations in North Carolina. AT&T asserted that the evidence offered through the affidavits accompanying its Petition paints a compelling picture of the competitive nature of all of AT&T's North Carolina markets. AT&T maintained that where new market entrants, such as cable companies and wireless carriers, provide choices to consumers, legacy regulation of AT&T should be further updated.

In particular, AT&T is asking the Commission to move three specific types of services from their present price plan basket to the Total Pricing Flexibility basket: (a) individual line residence (1FR) and individual line business (1FB) service only for customers in Rate Group 10; (b) stand-alone custom calling (vertical) features for all residential customers; and (c) local operator services, excluding verification and interrupt. Additionally, AT&T requested that the Commission approve changes to its price plan which would: (1) allow automatic movement of headroom between service baskets and (2) eliminate penalty provisions associated with retail service quality measures at the conclusion of the 2007-2008 plan year, or May 2008.

On December 10, 2007, AT&T filed a proposed revised price regulation plan permitting the Commission to rescind its approval of the changes contained in the proposed plan after AT&T provides a competitive marketplace update to the Commission in 2010. Specifically, AT&T's proposed revised price regulation plan includes a new Section XI – Submission of Competitive Data/Access Line Loss and a new Section XII – Changes to the Plan. Proposed Section XI requires AT&T to submit to the Commission, 18 months from the date of a Commission Order approving AT&T's Petition, a report that reviews the changes to the plan, including AT&T's assessment of the impact of such changes on the competitive market place. Proposed Section XI also requires that the report include the most current available information on: a) competitive data that depicts the presence of competitive offerings of telecommunications services, including, but not limited to, traditional land line service offered by AT&T and other vendors, service offered by wireless providers, and service offered by VoIP providers and b) the latest information on AT&T access line losses.

AT&T's proposed Section XII allows for AT&T's fifth revised plan to become effective on May 18, 2008 and specifies that the plan will remain in effect unless amended by the Commission. Proposed Section XII further specifies that if the Commission, after receiving the information described in proposed Section XI, determines that the changes included in the new plan have adversely impacted the affordability of basic local exchange service or otherwise adversely impacted the public interest, it shall notify AT&T of its findings within six months of the filing of AT&T's report outlined in Section XI and afford AT&T an opportunity to be heard. Proposed Section XII also states that any party, other than the Commission, that asserts that the changes included in the new price plan have adversely impacted the affordability of basic local exchange service or otherwise adversely impacted the public interest should have the burden of showing that such adverse impacts have occurred. Proposed Section XII specifies that if, after hearing, the Commission should find that the affordability of basic local exchange service or the public interest have been adversely impacted, the Commission may rescind any or all of the amendments included under the new plan that produce such adverse impacts and, as to the amendments that have specifically caused such adverse impact, require AT&T to operate under the currently-approved price plan which became effective on May 18, 2005. Finally, proposed Section XI states that, should the Commission not act within two years of the issuance of a Commission Order approving AT&T's Petition, AT&T's new price plan will be deemed permanently approved and may then only be modified at the request of AT&T in accordance with applicable state law.

STATUTORY REQUIREMENTS

G.S. 62-133.5(c) provides as follows:

> Any local exchange company subject to price regulation under the provisions of subsection (a) of this section may file an application with the Commission to modify such form of price regulation or for other forms of regulation. Any local exchange company subject to a form of alternative regulation under subsection (b) of this section may file an application with the Commission to modify such form of alternative regulation. Upon application, the Commission shall approve such other form of regulation upon finding that the plan as proposed (i) protects the affordability of basic local exchange service, as such service is defined by the Commission; (ii) reasonably assures the continuation of basic local exchange service that meets reasonable service standards established by the Commission; (iii) will not unreasonably prejudice any class of telephone customers, including telecommunications companies; and (iv) is otherwise consistent with the public interest. If the Commission disapproves, in whole or in part, a local exchange company's application to modify its existing form of price regulation, the company may elect to continue to operate under its then existing plan previously approved under this subsection or subsection (a) of this section [G.S. 62-133.5].

In order to approve modifications to AT&T's current price plan, the Commission must find that the revised plan meets all four statutory criteria set forth in G.S. 62-133.5(c). If the Commission determines the plan does not meet all of the four criteria, the Commission must disapprove the plan as proposed. The Company may then either elect to continue to operate under its current plan or submit a new proposed plan.

DESCRIPTION OF COMMISSION-AUTHORIZED PRICE PLAN

After careful consideration of the entire record in this proceeding, the Commission concludes that not all of AT&T's proposed price plan revisions, as filed, meet the four statutory criteria that must be met under G.S. 62-133.5(c). Therefore, the Commission cannot accept and approve, in its entirety, the proposed plan as filed by AT&T.

Nevertheless, we believe that we can approve a modified price plan for AT&T which does meet the four statutory criteria set out in G.S. 62-133.5(c). The Commission recognizes that the AT&T service territory, specifically including the exchanges in Rate Group 10, differs from the service territories of other ILECs in the State with respect to the extent and intensity of competitive activity. It thus follows that the degree and form of regulatory oversight among providers may vary as a function of these differences in demographics and levels of competition. Therefore, the Commission concludes that, subject to AT&T's agreement, the Company's current price plan may be modified as follows:

- Residential basic local exchange service for Rate Group 10 will be moved from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket;

- Business basic local exchange service for Rate Group 10 will be moved from the Moderate Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket;

- AT&T will be required to continue to maintain tariffs for all basic local exchange services in accordance with G.S. 62-133.5(d);

- AT&T's agreement to an indefinite waiver of the ratchet provision of G.S. 62-133.5(c) will be required as a condition precedent to the Commission's decision concerning the movement of basic local residential and business exchange services contained herein;

- Stand-alone custom calling (vertical) features and Touchstar[R] services for all residential customers will be moved from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket;

- Local operator services (excluding verification and interrupt) will be moved from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket;

- Operation of AT&T's self-effectuating service quality penalties provision will be suspended until further Order of the Commission without the removal of existing Section XI from AT&T's price regulation plan;

- AT&T's agreement to an indefinite waiver of the ratchet provision of G.S. 62-133.5(c) will be required as a condition precedent to the Commission's decision to suspend operation of the self-effectuating penalties provision of AT&T's price regulation plan; and

- AT&T will not be allowed to automatically move headroom from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket.

WHEREUPON, based on the foregoing and the entire record in this matter, the Commission now makes the following

<u>FINDINGS OF FACT AND CONCLUSIONS OF LAW</u>

1. AT&T is a "local exchange company" as that term is defined in G.S. 62-3(16a). AT&T is subject to the provisions of G.S. 62-110(f1). AT&T is currently subject to a price regulation plan approved pursuant to G.S. 62-133.5(c) and has sought revisions to that plan pursuant to G.S. 62-133.5(c). Thus, this matter is properly before the Commission for consideration, and AT&T meets all of the requirements for price regulation under G.S. 62-133.5.

2. The Commission-authorized plan will protect the affordability of basic local exchange service.

3. The Commission-authorized plan will reasonably assure the continuation of basic local exchange service that meets reasonable service standards established by the Commission.

4. The Commission-authorized plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

5. The Commission-authorized plan is otherwise consistent with the public interest.

DISCUSSION OF FINDINGS OF FACT AND CONCLUSIONS OF LAW

There are five contested issues to be resolved in this proceeding. The Commission will address each issue below and provide a discussion and decision on each.

ISSUE NO. 1: Should AT&T be allowed to move its individual line residence and individual line business services for customers in Rate Group 10 from the Moderate Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket?

DISCUSSION

AT&T is requesting that the Commission move individual line residential (or 1FR) and business (or 1FB) services for Rate Group 10 exchanges to the Total Pricing Flexibility Services basket within its price plan. Rate Group 10[1] includes the following exchanges: Apex, Arden, Belmont, Cary, Charlotte, Davidson, Denver, Greensboro, Huntersville, Julian, Knightdale, Locust, Monticello, Mount Holly, Raleigh, Selma, Stanley, Summerfield, Wendell, Wilmington, Winston-Salem, and Zebulon.

The crux of the issue concerning the detariffing of residential and business basic local exchange services concerns whether AT&T's request would comply with State law. The applicable legal standard is found in G.S. 62-133.5(c). The first prong of G.S. 62-133.5(c)(i) requires that AT&T's proposed plan "protect the affordability of basic local exchange service, as such service is defined by the Commission". Two questions immediately arise: What is "basic local exchange service" and what is "affordability"?

The Commission has previously defined "basic local exchange service" in Rule R17-1(a) as "[t]he telephone service comprised of an access line, dialtone, the availability of touchtone, and usage provided to the premises of residential customers or business customers within a local exchange area." This is a description of what has sometimes been referred to in this proceeding as "plain vanilla" local service - i.e., a single access line and those things which are necessary to make it work. In the instant case, AT&T seeks to have 1FR and 1FB service placed into the Total Pricing Flexibility Service basket. Generally speaking, a grant of total pricing flexibility is an implicit recognition that effective competition exists for these services.

On the affordability question, there is no dispute that today AT&T offers affordable basic local exchange service as defined by the Commission. However, the precise meaning of "affordability" is somewhat more opaque than the definition of "basic local exchange service". The Attorney General noted that the term "affordability" is not defined in the statute and argued that affordability should be judged from a common sense standpoint. The Attorney General asserted that the Commission should consider the citizens of North Carolina and what they would consider to be affordable basic local exchange service in light of how such service has been priced historically and in light of how it has been treated in past price regulation plan

[1] Rate Group 10 includes exchanges that have more than 150,000 exchange access lines and PBX trunks in their basic service area.

proceedings. The Attorney General argued that if the Commission gave AT&T complete discretion over prices, then, by definition, such a result would not comport with the affordability standard.

The Public Staff stated that "affordability" should be defined as ". . . as inexpensive as the market circumstances permit and as [sic] inexpensive enough to promote subscribership."

"Affordability" is not a technical term or a term of art, so the Commission must attempt to arrive at its ordinary meaning. Webster's New World Dictionary, Second Edition (1968), defines "afford" in pertinent part as "to have enough or the means for; bear the cost of without serious inconvenience . . . to be able (to do something) without risking serious consequences." These definitions support the view that affordability can vary with the financial means of the person in question. A well-off person may be able to bear the cost of telecommunications of the most modern and varied sort without serious inconvenience, while a person of more modest means may not be able to bear the cost of a much lesser range of services "without risking serious consequences" financially. Moreover, affordability is difficult to define absolutely because of various other choices individuals and households might make with whatever resources are available.

AT&T argued that, under its proposal to shift 1FR and 1FB services from the Moderate Pricing Flexibility basket to the Total Pricing Flexibility basket, competitive market forces will ensure that the affordability of basic local exchange service is protected. AT&T stated in its Brief that the important question for the Commission is whether alternatives are available from a variety of sources so that consumers collectively have options should AT&T attempt to raise its prices above competitive levels. AT&T argued that customers who do not consider a particular service to be a complete replacement for AT&T's basic local exchange service are protected by the fact that there are a substantial number of consumers who do see competitors' offerings as satisfactory alternatives. The Public Staff, the Attorney General, and the DOD/FEA all asserted that the market for basic local exchange service is not competitive enough to ensure that AT&T's basic local exchange service remains affordable.

The Commission notes that there are clearly two types of competition that AT&T faces. One is intramodal — i.e., landline — competition; the other is intermodal — primarily cable-based VoIP service and wireless service.

In support of its case that effective intramodal competition exists within Rate Group 10 exchanges, AT&T presented extensive evidence on the CLP market share data and the access line losses AT&T has sustained in the last few years. This data indicates that CLPs have achieved greater success in the telecommunications market in AT&T's Rate Group 10 exchanges then in exchanges in other rate groups.

As additional support for its Petition, AT&T described the intermodal competition it faces from wireless competitors. AT&T noted that the 2005 price plan record established that North Carolina ranked 11th in the country in the number of wireless subscribers with 4.5 million as of December 2003. AT&T stated that the latest data available from the FCC's June 2006 report shows that North Carolina continues to be ranked 11th in the United States in wireless subscribers, and that the number of subscribers has grown from 4.7 million to 6.2 million. AT&T asserted that wireless providers in AT&T's Rate Group 10 exchanges include Verizon, Alltel, Cingular, Sprint, and SunCom.

AT&T also noted that a striking development since the close of the last price regulation hearing is the pace at which wireless users in AT&T's service area have disconnected or elected not to subscribe to traditional wireline service. AT&T detailed evidence the Company had collected based on a survey completed in early 2006 of 600 wireless consumers across all of AT&T's rate groups. The survey was described in detailed in the affidavit of Mr. Shooshan. AT&T also supplied the number of wireless providers in AT&T's service area, and specifically in the Rate Group 10 exchanges, in Harrison Exhibit 1 which was attached to Ms. Harrison's affidavit.

Finally, in support of its Petition, AT&T cited to VoIP service provided via cable modem and "pure play" VoIP service, such as Vonage.

AT&T stated that the evidentiary record from the 2004 price regulation case established that Time Warner Cable served 1.3 million customers in North Carolina, and that approximately 950,000 of AT&T's retail customers live in exchanges where Time Warner Cable is present. AT&T maintained that the Company recently studied its exchanges with the smallest calling scope (Rate Groups 2 through 5) to determine the availability of alternative broadband connections to them. AT&T asserted that the results show that every exchange in even these rate groups had a cable television provider serving that area. AT&T argued that all exchanges in Rate Group 10 have an incumbent cable provider offering voice service to its entertainment and high-speed Internet service customers.

Further, AT&T noted that Time Warner Cable provides local service for $19.95 per month[1] if the subscriber has either high speed Internet service or basic cable service. AT&T acknowledged that not everyone has high speed Internet service, but stated that ". . . a high percentage of the people have basic cable service."

Ms. Harrison presented information on the substantial number of broadband providers and cable providers providing service as outlined in Harrison Exhibit 1.

AT&T noted in its Brief that, consistent with the information shown on Exhibit 3 to Ms. Harrison's Supplemental Affidavit, zip codes chosen for the exchanges of Burlington[2], Charlotte, Raleigh, and Wendell cover approximately 95% of each exchange. AT&T also noted that the FCC has not endorsed a more accurate method of providing information on broadband and wireless providers than the use of zip codes. AT&T further argued that whether zip codes perfectly match AT&T's exchange boundaries is not material to the Commission's evaluation of AT&T's total showing of competition in its markets because AT&T clearly is not going to

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[1] AT&T acknowledged that the rate increases to $29.95 per month after one year and stated that, even at $29.95 per month, it is very competitive with AT&T's basic local residential service.

[2] As noted by the Public Staff, Burlington is not a Rate Group 10 exchange.

subdivide an existing exchange so that it could potentially raise the rates in the portion of the exchange that might have fewer competitors.

The Commission finds that the evidence presented by AT&T shows that competition for business basic local exchange service has increased significantly in Rate Group 10 exchanges in recent years and that the totality of the evidence in this docket is sufficient to support moving business basic local exchange service to the Total Pricing Flexibility Services basket.

Specifically, in response to a Commission request for further information concerning AT&T's CLP competition outlined in Exhibit VH 1, AT&T filed detailed CLP data on December 10, 2007. The Commission has reviewed this confidential information and finds that there is an appropriate level of wireline competition to support moving AT&T's business basic local exchange service for Rate Group 10 from the Moderate Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket. The Commission finds that Rate Group 10 1FB service is subject to effective competition, primarily from CLP providers.

The Commission further finds and concludes that the evidence presented by AT&T is sufficient to justify moving residential basic local exchange service for Rate Group 10 exchanges to the High Pricing Flexibility Services, but not to the Total Pricing Flexibility Services, basket. Wireline and wireless competition has continued to increase for this market, but not to the extent or degree experienced by Rate Group 10 1FB customers. The continued growth in Rate Group 10 competition for 1FR service justifies allowing AT&T the additional pricing flexibility which the High Pricing Flexibility Services basket provides. It does not, however, justify moving this service to the Total Price Flexibility Services basket.

Finally, the Commission notes that G.S. 62-133.5(d) states as follows:

> Any local exchange company subject to price regulation under the provisions of subsection (a) of this section, or other alternative regulation under subsection (b) of this section, or other form of regulation under subsection (c) of this section **shall file tariffs for basic local exchange service** and toll switched access services stating the terms and conditions of the services and the applicable rates. . . . [Emphasis added.]

Under AT&T's proposed revised price regulation plan, basic local exchange service for Rate Group 10 customers would be moved to the Total Pricing Flexibility Services basket. The proposed revised plan provides that any future services within the Total Pricing Flexibility Services basket will be detariffed. The result of granting AT&T's request would therefore be to detariff basic local exchange service. Such a result would be patently inconsistent with the provisions of G.S. 62-133.5(d).

The Commission finds and concludes that G.S. 62-133.5(d) requires that basic local exchange services shall be tariffed. Even assuming that the Commission has the authority to do so, we find no basis to waive this statutory requirement, even for the Rate Group 10 1FB service that will be moved to the Total Pricing Flexibility Services basket. This will allow the Commission to continue to monitor Rate Group 10 1FB rates in particular in order to ensure that

AT&T's price plan continues to protect the affordability of basic local exchange service on an ongoing basis. In addition, it will ensure that the level of competition that AT&T faces in the larger exchanges in Rate Group 10 will operate to the benefit of customers in all Rate Group 10 exchanges.

In our April 29, 2005 Order Approving Modified Price Regulation Plan for AT&T, the Commission found that the increased pricing flexibility granted by the Commission for basic local exchange services was justified because of the increased competition that existed for such services in AT&T's service area, both at an intermodal and intramodal level. The Commission remarked that the "meaningful and pervasive" competition existing in 2005 contrasted sharply with the extent of such competition in 1996, when there was little or no competition for basic local exchange service.

The level of "meaningful and pervasive" competition in Rate Group 10 has continued to increase such that a further loosening of price constraints as they apply to residential and business basic local exchange services for Rate Group 10 exchanges is justified.

AT&T is unique in North Carolina in that its service territory encompasses North Carolina's largest metropolitan areas, including Charlotte, Raleigh, Greensboro, Winston-Salem, and Wilmington, all of which are Rate Group 10 exchanges. Further, the Commission stated in its *April 29, 2005 Order* that the level of competition in AT&T's service territory is significantly greater than in other areas of the State served by other ILECs and that AT&T's competitive losses in North Carolina have been significantly greater than those of other ILECs. Although these statements were based, in part, on the competition study performed by Research Triangle Institute (RTI) in 2004, the Commission finds nothing in this current proceeding that would support a finding that this situation has changed. In fact, we believe that the level of competition faced by AT&T, particularly in its Rate Group 10 exchanges, has continued to increase. This conclusion is supported by the totality of the evidence offered by AT&T in this case.

AT&T has presented detailed information on the significant competitive alternatives to its basic local exchange service in Rate Group 10 provided by wireline CLPs, wireless carriers, and VoIP providers. After careful examination of the data presented in this docket, the Commission concludes that the degree of Rate Group 10 competition, both intermodal and intramodal, which AT&T faces today and which the Company will likely face in the future is meaningful and pervasive and supports the decision to move Rate Group 10 basic local exchange service for residential customers to the High Pricing Flexibility Services basket and to move Rate Group 10 basic local exchange service for business customers to the Total Pricing Flexibility Services basket. The Commission believes that these changes will ensure that AT&T's new price regulation plan is in compliance with G.S. 62-133.5(c)(i) in that it will protect the affordability of basic local exchange service, as such service is defined by the Commission, and that such changes are consistent with the public interest as required by G.S. 62-133.5(c)(iv).

Notwithstanding the foregoing discussion and conclusions, the Commission is concerned about the effect of the so-called "ratchet" mechanism contained in the last sentence of G.S. 62-133.5(c) on customers in Rate Group 10 exchanges. The Commission believes that moving Rate Group 10 residential basic local exchange service to the High Pricing Flexibility

Services basket and moving business basic local exchange service to the Total Pricing Flexibility Services basket is appropriate today in light of the totality of the competitive information presented in this proceeding and is consistent with the goal of continuing North Carolina's transition to an effective competitive telecommunications market. However, G.S. 62-133.5(c) imposes upon the Commission a continuing statutory obligation to make sure that AT&T's price plan continues to protect the affordability of Rate Group 10 basic local exchange service. As we have found since 1996, the state of competition in the telecommunications industry is subject to change and is sensitive to, among other things, technological and regulatory change and innovation. The dynamic nature of competition in this sector means that competitive forces might not always adequately protect the affordability of basic local exchange service. Given our clear and absolute duty to do so found in statute, the Commission needs the flexibility to be able to revisit its decision in this regard if experience shows that the new price plan does not, in fact, protect the affordability of basic local exchange service.

In principle, AT&T has already accepted the fact that the ratchet mechanism may be an impediment to Commission approval of the Company's proposal revised plan. In its December 10, 2007 revision, AT&T proposed a one-time and temporary waiver of the ratchet mechanism. The Commission does not believe that the waiver proposed by AT&T is sufficient in degree to permit the Commission to gauge the competitive landscape in North Carolina. The obligation of the Commission pursuant to G.S. 62-133.5(c) is to ensure that price plans protect basic local exchange service at affordable rates. That obligation is a fundamental and continuing obligation which the Commission can only effectively and confidently discharge on a going-forward basis if there is a broader waiver of the ratchet mechanism.

Therefore, the Commission's decision with respect to Rate Group 10 is contingent on AT&T's agreement to an indefinite waiver of the ratchet provision found in G.S. 62-133.5(c). The Commission can only approve a price plan for AT&T that will protect the affordability of basic local exchange service. The Commission believes that its decision in this regard is fair and a reasonable accommodation that promotes further transitioning of North Carolina's telecommunications industry to an effectively competitive telecommunications market governed primarily by competitive forces while fulfilling the Commission's statutory obligations under G.S. 62-133.5(c). The Commission is convinced that an indefinite waiver of the ratchet mechanism as applied to its decision to move Rate Group 10 residential basic local exchange service to the High Pricing Flexibility Services basket and to move business basic local exchange service to the Total Pricing Flexibility Services basket is reasonable and appropriate and is the <u>only</u> solution which will allow the Commission to meet all of the statutory requirements of G.S. 62-133.5(c).

The Commission believes that the result reached here moves AT&T significantly further along in the transition to a fully and effectively competitive telecommunications market while providing the statutorily required protections for customers. If AT&T and the Commission are correct about the ability of competition to protect the affordability of basic local exchange service, such waiver is of no consequence. However, if we are mistaken, such a waiver is necessary to protect the statutory right of AT&T's customers to such service.

CONCLUSIONS

The Commission concludes that AT&T should be allowed to move residential basic local exchange service for Rate Group 10 from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket. The Commission further concludes that it is appropriate to allow AT&T to move business basic local exchange service for Rate Group 10 from the Moderate Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket. The Commission finds these changes to be reasonable and appropriate, provided that AT&T continues to maintain tariffs for all basic local exchange service in accordance with G.S. 62-133.5(d) and agrees to an indefinite waiver of the ratchet provision relating to the Commission's decision concerning the movement of Rate Group 10 basic local residential and business exchange services contained herein. Such action satisfies the requirements of G.S. 62-133.5(c) and is consistent with the public interest.

ISSUE NO. 2: Should AT&T be allowed to move its stand-alone custom calling (vertical) features and Touchstar[R] services for all residential customers from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket?

DISCUSSION

Currently, custom calling features and Touchstar[R] services are in the High Pricing Flexibility Services basket of AT&T's price regulation plan. The individual rate element constraint for raising the rate for services in the High Pricing Flexibility Services basket is 20 percent per year and the revenue cap for the entire basket is 2½ times the rate of inflation.

AT&T's current tariff rates for residential Custom Calling Features are as follows:

Custom Calling Feature	Current Rate Per Month
Call Forwarding Variable	$3.95
Three-Way Calling	$5.95
Call Waiting	$5.88
Speed Calling – 8-Code	$3.12
Speed Calling – 30-Code	$5.95
Call Forwarding Busy Line	$1.50
Call Forwarding Don't Answer	$1.50
Call Forwarding Don't Answer – Ring Control	$1.50
Customer Control of Call Forwarding Busy Line	$3.50
Customer Control of Call Forwarding Don't Answer	$3.50
Call Forwarding Busy Line Multiple Simultaneous Calls	$2.35
Call Forwarding Don't Answer Multiple Simultaneous Calls	$2.35
Call Forwarding Variable Multiple Simultaneous Calls	$3.55
Remote Access	$7.00
Call Waiting Deluxe	$7.95
Three-Way Calling with Transfer	$6.95

AT&T's current tariff rates for residential Touchstar[R] Services are as follows:

Touchstar[R] Service	Nonrecurring Charge (Per Use)	Current Rate Per Month
Call Return	$1.05	$6.95
Repeat Dialing	$1.05	$5.95
Call Tracing	$1.00	$5.95
BusyConnect	$1.05	N/A
Call Selector	N/A	$5.95
Preferred Call Forwarding	N/A	$5.95
Call Block	N/A	$5.95
Caller ID – Basic	N/A	$8.00
Caller ID – Deluxe (with ACR)	N/A	$9.00
Anonymous Call Rejection (ACR)	N/A	$4.00
Caller ID – Deluxe (without ACR)	N/A	$9.00

The Commission notes that business custom calling features and Touchstar[R] services were moved to the Total Pricing Flexibility Services basket in connection with the 2005 modifications to AT&T's price regulation plan. The Commission is not aware of any adverse impacts resulting from that treatment of business custom calling features and Touchstar[R] services.

AT&T provided evidence in this proceeding that, from December 2000 to December 2006, custom calling features for residential customers, such as Call Waiting, Call Return, Three-Way Calling, and Call Forwarding, have experienced a significant drop in demand in the aggregate[1]. AT&T attributed this decrease in demand to the fact that consumers have found more value in subscribing to packages and bundles offered by AT&T and its competitors. AT&T noted that, even if customers have just one a la carte feature, such as Caller ID, AT&T and its competitors offer packages and bundles that offer considerable value over a la carte features. AT&T further stated during the oral argument that AT&T has "lost 75% of the market share" for custom calling features.

The Commission notes that, when making decisions as to the baskets into which non-basic services are placed within a price regulation plan, the standard has been and continues to be twofold: whether there are adequate competitive alternatives to the service and the discretionary nature of the service. Further, while G.S. 62-133.5(c) requires that the Commission approve a plan that protects the affordability of basic local exchange service, residential custom calling features are not basic local services which are subject to the greater degree of statutory price protection. The competitive market will provide the necessary degree of price constraint for these discretionary services. In the instant case, AT&T has offered convincing evidence that it has experienced a significant drop in demand for residential custom calling features in recent years and that these services are discretionary in nature. This decline in demand for these services demonstrates that market forces can serve to adequately protect customers. For these reasons, the Commission concludes that AT&T's price plan, with custom calling features and

[1] The specific percentage was filed confidentially.

Touchstar[R] services for residential customers in the Total Pricing Flexibility Services basket, will satisfy the requirements of G.S. 62-133.5(c) and will be consistent with the public interest.

Therefore, the Commission concludes that it is appropriate and consistent with the public interest to allow AT&T to move residential custom calling features and Touchstar[R] services from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket.

CONCLUSIONS

The Commission concludes that AT&T should be allowed to move residential custom calling features and Touchstar[R] services from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket. Such action satisfies the requirements of G.S. 62-133.5(c) and is consistent with the public interest.

ISSUE NO. 3: Should AT&T be allowed to move its local operator services (excluding verification and interrupt) from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket?

DISCUSSION

AT&T has requested in its Petition to move local operator services (excluding verification and interrupt) from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket. The current rates for the local operator services AT&T is requesting be moved are as follows:

Type of Service	Rate
Station-to-Station customer dialed credit card local call	$0.95
Station-to-Station operator assisted sent-paid, collect, third number, and non-customer dialed calling card calls	$1.40
Person-to-Person operator assisted local call	$2.52

The Commission notes that the individual rate element constraint for services in the High Pricing Flexibility Services basket is 20 percent per year and that the revenue cap for the entire basket is 2½ times the rate of inflation.

AT&T provided evidence in this proceeding that, from December 2000 to December 2006, it has seen a very significant decline in monthly local operator assisted calls. AT&T noted that access line loss and increased use of wireless phones have contributed to the large decline in monthly local operator assisted calls. The Public Staff contended that approving AT&T's request might adversely impact a consumer's ability to access AT&T's local operator services using public payphones. AT&T responded that the consumer would probably have a cell phone, and if not, would not mind paying the price in the event of an emergency. AT&T also cast doubt on the availability of payphones in such circumstances. AT&T asserted that it does not have payphones in service anymore and that most ILECs do not provide payphones. AT&T noted that some CLP and payphone operators provide their own operator services while others subscribe to operator services from the many alternatives available, including Qwest, Intellicall Operator Services (IOS), and others. AT&T argued that, with direct dialing, the elimination of payphones, and the manner in which people communicate today, operator services are truly a dinosaur.

The Commission agrees that the extremely significant decrease in the number of monthly calls for local operator assisted calls supports AT&T's request to move these services to the Total Pricing Flexibility Services basket of its price regulation plan. Further, the Commission believes that movement of local operator services to the Total Pricing Flexibility Services basket of AT&T's price plan will satisfy the requirements of G.S. 62-133.5(c) and will be consistent with the public interest. While G.S. 62-133.5(c) requires that the Commission approve a plan that protects the affordability of basic local exchange service, local operator services are not basic local services which are subject to the greater degree of statutory price protection. The competitive market will provide the necessary degree of price constraint for these discretionary services.

CONCLUSIONS

The Commission concludes that AT&T's request to move local operator services from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket should be granted. Such action satisfies the requirements of G.S. 62-133.5(c) and is consistent with the public interest.

ISSUE NO. 4: Should AT&T be allowed to eliminate penalty provisions associated with retail service quality measures at the conclusion of the 2007-2008 plan year (May 2008)?

DISCUSSION

Section XI of AT&T's price regulation plan contains self-effectuating service penalties which are based on the service quality objectives adopted by the Commission in Rule R9-8. Eight of the measures in Rule R9-8 are included in the plan; the plan excludes Business Office and Repair Service Answertimes. In addition, for the Out-of-Service Troubles Cleared Within 24 Hours service objective, penalties are assessed only if AT&T fails to achieve a 90% objective; the Rule R9-8 objective for this measure is 95%. Under Section XI of AT&T's plan, if AT&T's yearly average statewide service results for a given service measure satisfy the objective, no penalty will be assessed for that service measure even though one or more monthly measurements of that objective are missed.

AT&T has requested that the Commission allow the Company to remove Section XI from its price regulation plan. Verizon supports AT&T's request in this regard, while the Attorney General, DOD/FEA, and the Public Staff all recommend that the Commission deny AT&T's request to remove Section XI from the Company's price regulation plan.

AT&T concedes that it will continue to be subject to the penalty provisions of G.S. 62-310 and the requirements for the collection of service quality data. AT&T argued that market discipline will serve to keep its service quality in compliance with Commission standards and that, in fact, AT&T has not had to pay any self-effectuating penalties since Section XI was instituted in 2000.

After careful consideration of the filings on this issue, the Commission concludes that Section XI has, generally speaking, been a success. The fact that no penalties have been incurred since Section XI was instituted in 2000 — in contrast to the "rough patch" that AT&T experienced before — points to that success. The Commission believes that AT&T should be rewarded for this marked improvement in service quality. The Commission is not persuaded that the absence of penalties is attributable wholly to a fear of penalties on the part of AT&T. Compliance has also likely improved because of the demands of the competitive marketplace as well as AT&T's commitment to excellence.

Given that AT&T has been in compliance with Section XI for a number of years, the Commission finds that it is appropriate to modify the application of that Section at this time. The Commission has elected to modify Section XI, as opposed to eliminating it from the plan because we do not believe that it is in the public interest at this point to abandon the self-effectuating penalty mechanism altogether. The Commission fully expects that AT&T will continue to provide a level of service to its North Carolina consumers that meets or exceeds the applicable service quality objectives. However, there is always the possibility that quality of service problems might recur. If this were to happen, and given the so-called "ratchet mechanism" embodied in G.S. 62-133.5(c), the Commission would be without the means necessary to protect the public interest and to fulfill its statutory obligation to ensure reasonable service quality if Section XI were to be eliminated from AT&T's price plan.

Accordingly, after careful consideration of the filings on this issue, the Commission concludes that it would be consistent with G.S. 62-133.5(c)(i)-(iv) for the Commission to suspend, pending further order, the collection of any penalties that may be incurred pursuant to Section XI, subject to AT&T's agreement to an indefinite waiver of the ratchet provision contained in G.S. 62-133.5(c). The Commission believes that AT&T has earned this decision by keeping its service quality at a level high enough to avoid incurring any penalties since 2000 under the provisions of its current price plan.

The Commission emphasizes that AT&T will still be expected to comply with the quality of service objectives set forth in Rule R9-8 and that Section XI will remain in the Company's price plan. It is only the <u>collection</u> of any penalties that may be incurred which will be suspended. Existing service quality reporting requirements will remain in effect. If service quality lapses occur, then the Commission, on its own motion or upon petition of any other party, may lift the suspension and revive the operation of the plan's self-effectuating penalties provision on a prospective basis[1]. The Commission's decision in this regard seeks to balance AT&T's desire to avoid the self-effectuating penalties process with the public interest in having a quick and efficient mechanism for the collection of service quality penalties, *should it prove necessary*. It is therefore a fair, reasonable, and necessary condition. In addition, the Commission believes that G.S. 62-133.5(c) requires this result since it requires a price plan to reasonably assure the continuation of basic local exchange service that meets reasonable service

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[1] In so ruling, the Commission notes that the Section XI process compares favorably with the more drawn-out and cumbersome process mandated under G.S. 62-310, which requires the Commission to institute an action for the recovery of penalties in Wake County Superior Court. Therefore, it is more administratively efficient to retain the flexibility to reinstate the Commission's ability to collect penalties under Section XI of the plan.

standards established by the Commission. If AT&T and, with this decision the Commission, are correct about the ability of competition to protect service quality, such waiver is of no consequence.

Finally, the Commission observes that a number of price plan companies have self-effectuating penalty provisions and some have paid penalties. This decision is not to be construed as a precedent for the elimination or suspension of such provisions. Instead, any request for such relief will be examined carefully on a case-by-case basis.

CONCLUSIONS

The Commission concludes that the collection of any penalties pursuant to Section XI of AT&T's price plan should be suspended pending further order, subject to AT&T's agreement to an indefinite waiver of the ratchet provision contained in G.S. 62-133.5(c). Such action satisfies the requirements of G.S. 62-133.5(c), in that it will reasonably assure the continuation of basic local exchange service that meets the service standards established by the Commission and is otherwise consistent with the public interest.

<u>ISSUE NO. 5</u>: **Should AT&T be allowed to automatically move headroom from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket?**

DISCUSSION

In addressing its request for automatic headroom[1] movement, AT&T noted that its current plan contains two categories of services that continue to be price regulated. AT&T noted that the Moderate Pricing Flexibility Services category contains revenues that are over seven times larger than those in the High Pricing Flexibility Services category. As such, AT&T stated that it is sometimes necessary to move available headroom from the Moderate Pricing Flexibility Services category to the High Pricing Flexibility Services category. The Public Staff reviews such requests and has recommended approval of the requested transfer in every case. AT&T asserted that, under its proposed change, the Public Staff would continue to review the detailed price-outs associated with each filing. However, for the ease of administration, AT&T is requesting that the Commission allow automatic movement of headroom from the Moderate Pricing Flexibility Services category to the High Pricing Flexibility Services category.

During the oral argument, AT&T asserted that maintaining the status quo, wherein the Public Staff reviews any requests for movement in headroom, is a regulatory burden and is not economically efficient. AT&T also noted the regulatory cost of filing a movement request every time.

The DOD/FEA stated that it did not oppose the Commission granting AT&T's request in this regard. The Attorney General did not specifically address this issue in any of its comments

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[1] The difference between the revenue constraint and total revenues produced in a service category is referred to as headroom. AT&T's price regulation plan defines headroom as, "[t]he dollar value of the difference between the PRI [Price Regulation Index] and SPI [Service Price Index] for a specific service category."

or during the oral argument. However, the Public Staff opposed the request and argued that AT&T's headroom movement proposal would render the revenue constraint for the High Pricing Flexibility Services category essentially meaningless. According to the Public Staff, AT&T's proposed plan could result in moving sufficient headroom to allow it to raise each rate element in the High Pricing Flexibility Services basket by 20 percent, thus effectively eliminating the benefit of the revenue constraint. The Public Staff also noted that, in any given year, revenues within a basket may be increased by the amount of the revenue constraint for that year, plus any headroom accumulated in previous years.

The Public Staff noted in the affidavit of Nat Carpenter that each of AT&T's prior requests to move headroom were relatively limited in nature and were made for the purpose of accomplishing a needed rate rebalance, rather than merely securing more revenue beyond the level that the revenue constraint would otherwise allow. Mr. Carpenter maintained that the unbridled flexibility to transfer headroom across categories that AT&T has requested would not necessarily involve a rebalance; instead, it would free AT&T to implement headroom transfers designed solely for the purpose of securing additional revenue. Mr. Carpenter asserted that AT&T's desire to undertake such transfers, while understandable, was not necessarily in the public interest.

As previously noted, the current pricing constraints in AT&T's Plan are as follows:

<u>Moderate Pricing Flexibility Services basket:</u>
Rate element constraint of 10 percent per year
Revenue constraint of 1½ times the increase in GDPPI

<u>High Pricing Flexibility Services basket:</u>
Rate element constraint of 20 percent per year
Revenue constraint of 2½ times the increase in GDPPI

AT&T's price regulation plan was deliberately structured to place services in baskets based upon the level of competition for a particular service and the extent to which each service was discretionary. Each basket contains two specific pricing constraints: one on each rate element and one on the total revenues produced from all of the services in a basket. AT&T has asserted in this proceeding that it is administratively burdensome for the Company to seek review and approval from the Public Staff and the Commission whenever it desires to move headroom between baskets.

The Commission notes that the currently-approved price regulation plan does not contain general provisions for the movement of headroom[1], and previous requests by AT&T have been couched as proposed waivers to the price plan. Therefore, there are no guidelines for such requests and AT&T has not pointed to any instance where either the Public Staff or the Commission has failed to respond in a timely fashion to AT&T's requests to move headroom.

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[1] However, Section V.B.5 of AT&T's currently-approved price regulation plan specifies that AT&T may transfer headroom created by reductions in access charges to the High Pricing Flexibility Services category.

Even if the Commission were to grant AT&T's request to be allowed to automatically move headroom, AT&T has conceded that the Public Staff would nevertheless continue to review the detailed price-outs associated with each filing. This contradicts AT&T's assertion that the current process is administratively burdensome. If price-outs will still be filed by AT&T and reviewed by the Public Staff, the Commission does not see how allowing automatic movement of headroom would significantly lessen the administrative burden on AT&T. It is reasonable and appropriate for the Public Staff to continue to review all requests for movement of headroom expeditiously and for the Commission, on a timely basis, to either grant or deny each request based on the specific circumstances surrounding each request.

Further, the Commission notes that its decision in this Order allows AT&T to transfer basic local exchange service for residential basic local exchange service customers in Rate Group 10 from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket. In addition, certain services have been moved from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket. Therefore, it is likely that overall revenues may decrease in the Moderate Pricing Flexibility Services basket and increase in the High Pricing Flexibility Services basket, making AT&T's request in this regard less significant.

The Commission, therefore, finds it appropriate to deny AT&T's request to automatically move headroom from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket.

CONCLUSIONS

The Commission concludes that AT&T's request to be allowed to automatically move headroom from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket should be denied.

WHEREUPON, the Commission reaches the following

OVERALL CONCLUSIONS

Based upon the foregoing discussion and the entire record in this matter, the Commission finds that it is appropriate to authorize a modified price plan for AT&T which:

- Allows AT&T to move residential basic local exchange service for Rate Group 10 from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket;

- Allows AT&T to move business basic local exchange service for Rate Group 10 from the Moderate Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket;

- Requires AT&T to continue to maintain tariffs for all basic local exchange services in accordance with G.S. 62-133.5(d);

- Includes an indefinite waiver of the ratchet provision of G.S. 62-133.5(c) as a condition precedent to the Commission's decision concerning the movement of basic local residential and business exchange services contained herein;

- Allows AT&T to move its stand-alone custom calling (vertical) features and Touchstar[R] services for all residential customers from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket;

- Allows AT&T to move its local operator services (excluding verification and interrupt) from the High Pricing Flexibility Services basket to the Total Pricing Flexibility Services basket;

- Allows a suspension of the operation of AT&T's self-effectuating service quality penalties provision until further Order of the Commission without the removal of existing Section XI from AT&T's price regulation plan;

- Includes an indefinite waiver of the ratchet provision of G.S. 62-133.5(c) as a condition precedent to the Commission's decision to suspend operation of the self-effectuating penalties provision of AT&T's price regulation plan; and

- Denies AT&T's request to be allowed to automatically move headroom from the Moderate Pricing Flexibility Services basket to the High Pricing Flexibility Services basket.

The Commission invites and requests AT&T, subject to the provisions of this Order, to accept the modifications and conditions set forth above and to file an amended price regulation plan that incorporates these modifications and conditions for final approval by the Commission. If AT&T accepts the terms of this Order and files a fully-compliant revised plan, the Commission will approve that plan without further hearing or comment.

IT IS, THEREFORE, SO ORDERED.
ISSUED BY ORDER OF THE COMMISSION.

This the 14th day of April, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Chairman Edward S. Finley, Jr. did not participate in this decision.

Commissioner Robert V. Owens, Jr. dissents with respect to the Majority's decision on Issue No. 5, concerning automatic headroom movement, but concurs with the Commission's decisions on all other issues.

bp041408.01

DOCKET NO. P-294, SUB 30

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Sprint Communications Company, L.P.	)	ORDER RULING ON
for Arbitration of Interconnection Agreement with	)	OBJECTIONS AND
Randolph Telephone Company	)	REQUIRING THE FILING
	)	OF A COMPOSITE
	)	AGREEMENT

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioner James Y. Kerr, II[1], and Commissioner William T. Culpepper, III, the Original Panel Members, and Chairman Edward S. Finley, Jr., Commissioner Robert V. Owens, Jr., Commissioner Lorinzo L. Joyner, and Commissioner Howard N. Lee

BY THE COMMISSION: On August 29, 2008, the Commission issued its *Recommended Arbitration Order* (*RAO*) in this docket[2]. The Commission Panel made the following:

FINDINGS OF FACT

1. Randolph is a rural telephone company within the meaning of Section 251(f)(1)(A) of the Act, and, as such, is exempt from the obligations imposed by Section 251(c) of the Act, subject to the Commission's authority to terminate its exemption.

2. Randolph has not waived its right to the exemption granted by Section 251(f)(1)(A) of the Act.

3. In accordance with Section 251(f)(1)(A) of the Act, Sprint has made a bona fide request to terminate Randolph's rural telephone company exemption from the obligations imposed by Sections 251(c)(1) and (2).

4. Sprint's request for a partial termination of Randolph's rural telephone company exemption is technically feasible.

5. Sprint's request for a partial termination of Randolph's rural telephone company exemption is not unduly economically burdensome and is consistent with Section 254 of the Act (other than subsections (b)(7) and (c)(1)(D) thereof).

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[1] Commissioner Kerr resigned from the Commission effective August 31, 2008.

[2] The *RAO* was issued by Commissioner Ervin, presiding, and Commissioners Kerr and Culpepper. Since Commissioner Kerr, an Original Commission Panel member, resigned from the Commission effective August 31, 2008, this decision has been made by the Full Commission.

6. Sprint's request for a partial termination of Randolph's rural telephone company exemption should be granted, and Randolph should be required to comply with the provisions of Sections 251(c)(1) and (2) of the Act.

7. Sprint is entitled to interconnect and exchange traffic with Randolph pursuant to Sections 251(a) and (b) of the Act as a wholesale telecommunications provider of services to other carriers, including Voice over Internet Protocol (VoIP) telephony service.

8. The parties, with the assistance of the Public Staff, should negotiate a definition of local exchange traffic that is consistent with the modifications described in this Order for use in the ICA.

9. Randolph is required to provide number portability to Sprint.

10. The interconnection agreement between Sprint and Randolph should not limit the number of port requests allowed per business day.

11. The directory-related indemnity and liability provisions proposed by Randolph should not be included in the ICA in their present form, but the parties should determine, in a manner consistent with the *LEXCOM-Time Warner Recommended Arbitration Order (RAO)*, what indemnity and limitation of liability provisions, if any, should be included in the ICA.

12. It is appropriate to order Sprint and Randolph to further negotiate the issue of deposits and advance payment requirements. First and foremost, the parties, with the assistance of the Public Staff, should discuss whether a deposit and an advance payment requirement are necessary, given Sprint's contention that zero or minimal money will be changing hands between Sprint and Randolph on a monthly basis. If the parties determine that a deposit and an advance payment requirement are necessary, then the parties, with the assistance of the Public Staff, should mutually develop appropriate language based on the Commission's previous decisions concerning deposits and advance payment requirements.

13. Attachment I proposed by Randolph, subject to certain modifications, should be included in the ICA. It should include the directory delivery fees and access charges on which the parties have agreed. The parties, with the assistance of the Public Staff, should seek to reach an agreement on other charges to be included in the attachment.

On September 29, 2008, Randolph Telephone Company (RTC) filed Objections to the *RAO*. Specifically, RTC objected to Findings of Fact Nos. 5, 6, and 7.

Also on September 29, 2008, comments were filed by Star Telephone Membership Cooperative (Star), an interested company not party to this proceeding. Star stated that the parties should have been permitted to negotiate and that the Commission's ruling may not promote competition for rural customers.

On September 30, 2008, the Commission issued an *Order* requesting comments and reply comments on the Objections and comments filed concerning the *RAO*.

On October 1, 2008, RTC filed revised copies of Randolph Projection Analysis 1 and Randolph Projection Analysis 2 and requested that the revised versions replace the versions included in Randolph's September 29, 2008 Objections.

On October 8, 2008, the Commission issued an *Order Suspending Composite Agreement Date* pending further order to be issued at such time as the proceeding to consider the objections and comments has been resolved.

On October 10, 2008, the National Telecommunications Cooperative Association (NTCA) filed a Motion to Accept Late Filed Objections to the *RAO*.

On October 22, 2008, Sprint filed its objections to the NTCA's Motion.

The Commission finds it appropriate to grant the NTCA's Motion and herein accepts the NTCA's comments as filed.

Initial comments were filed by Sprint on October 23, 2008 and by the Public Staff on October 24, 2008. Reply comments were filed by RTC on November 14, 2008.

On November 20, 2008, three members of the North Carolina General Assembly, specifically, Senator Tillman, Representative Brubaker, and Representative Hurley, filed a letter with the Commission expressing their concerns with the *RAO* issued by the Commission in this docket. The letter asked that the Commission consider three specific options in its final ruling in this matter and also urged the Commission to give careful consideration to the policy implications of the decisions embodied in the *RAO*.

Although a Commission Panel issued the original *RAO*, the Objections addressed in this Order have been decided by the Full Commission due to Commissioner Kerr's resignation from the Commission effective August 31, 2008.

Following is a discussion, by Finding of Fact, of the outstanding Objections to the *RAO*.

<u>ISSUE NO. 1 - MATRIX ISSUE NO. 1</u>: Is Randolph exempt from interconnecting with Sprint pursuant to the requirements of Sections 251(a) and (b)?

<u>FINDING OF FACT NO. 5</u>: Sprint's request for a partial termination of Randolph's rural telephone company exemption is not unduly economically burdensome and is consistent with Section 254 of the Act (other than subsections (b)(7) and (c)(1)(D) thereof).

INITIAL COMMISSION DECISION

The Commission concluded that it is under no illusion that it is able to accurately predict the future. The Commission stated that it can merely make the best possible predictive judgment given the evidence in the record. Over the long term, RTC's survival and profitability will depend on the skill and insight of its management, as well as many other factors that cannot now be foreseen. The Commission noted that, in the immediate future, it does not believe that the interconnection requested by Sprint, and the resulting competition between RTC and Sprint and Time Warner Cable (TWC), will place an undue economic burden on RTC or significantly interfere with the availability of universal service to RTC's customers. Accordingly, the Commission concluded that Sprint's request for partial termination of RTC's exemption under Section 251(f)(1) of the Telecommunications Act of 1996 (Act) from the obligations of Sections 251(c)(1) and (2) should be granted.

MOTIONS FOR RECONSIDERATION

SPRINT: Sprint did not object to this Finding of Fact.

RTC: RTC objected to Finding of Fact No. 5, which concluded that it would not be "inappropriate" or "excessively" burdensome to expose RTC to the economic consequences of competition from the Sprint/TWC business model. According to RTC, the Commission failed to give adequate weight to the evidence and analysis that RTC presented, which illustrated the extent of Sprint's understatement of the line losses, which RTC would suffer from the competitive entry of Sprint/TWC in part of RTC's service area. RTC asserted that those line losses will determine the economic burden imposed on RTC and that the economic burden resulting from those line losses will adversely impact the continued attainment of universal service objectives in the majority of RTC's service area - an area where Sprint/TWC will not offer service.

NON-PARTY COMMENTS

STAR: Star did not file specific objections to Finding of Fact 5. It did note, however, that the Commission's decision may not promote competition for rural customers.

NTCA: NCTA stated in its comments that it objected to the *RAO's* Finding of Fact No. 5 to the effect that Sprint's request for a partial termination of RTC's rural telephone company exemption was not unduly economically burdensome and is consistent with the universal service obligations established in Section 254 of the Act. According to NCTA, the *RAO* reached this conclusion based upon a perfunctory and incomplete analysis of the impact of the proposed competitive entry and the resulting impact upon the achievement of the universal service goals set out in Section 254. Instead of focusing on RTC management's response to the competition provided by Sprint and Time Warner, NCTA argues that the Commission should have focused its examination on the effects of competition on RTC. NCTA notes that the Commission should have given more consideration to "cream skimming" because the benefits of competition are diminished when a competitor is permitted to serve the easiest and most profitable customers. In that situation, NCTA argues that universal service principles are not advanced and that the incumbent's remaining customers are harmed due to the increased costs that result from that approach.

INITIAL COMMENTS

SPRINT: In its comments, Sprint noted that RTC objected to the Commission's recommended Finding of Fact No. 5 to the effect that termination of RTC's rural exemption is not unduly burdensome. In response to RTC's contention, Sprint asserted that it is beyond dispute that RTC is a financially sound and profitable company and that it is undeniable that competition brings the potential for some economic burden in any industry. In a regulated industry in which government has required the incumbent to provide certain things to potential competitors, some economic burden is likely. Further, Sprint noted that the Commission analyzed the only evidence presented by either party to the proceeding, i.e., the testimony of Sprint witness Farrar, to determine, in light of the whole of the potential economic burden resulting from competitive entry by Sprint/TWC, whether Sprint could demonstrate that the burden is not undue. Despite having produced no direct evidence on the matter, Sprint argues that RTC dismissed the Commission's extensive analysis of the economic burden, in large measure, by challenging Sprint's evidence of projected line losses. Sprint maintained that the Commission correctly analyzed the economic data and reached the correct conclusion.

Finally, Sprint addressed RTC's contention that providing service only in the Town of Liberty would constitute "cream skimming." Sprint noted that it has consistently maintained that competitive service will be offered to ALL business and residential customers for whom TWC facilities are available, a number which currently includes persons or entities using nearly two thirds of Randolph's access lines. (revised RGF Exhibit 7). Sprint and TWC stated that they cannot be asked, expected or required to do any more than they are capable of doing, i.e., offer service to all customers within their collective footprint. Thus, the Commission should not be swayed by RTC's attempt to distract the Commission from the benefits gained by consumers, who finally may, over 12 years after the passage of the Telecommunications Act, have the opportunity to purchase services from a local service provider other than RTC.

PUBLIC STAFF: The Public Staff maintained that the Commission should not revise Finding of Fact No. 5, in which the Commission held that the proposed deployment of the Sprint/TWC business model in RTC's service area would not impose an undue economic burden on RTC or be inconsistent with Section 254 of the Act. The Public Staff stated that a review of the Commission's *RAO* reveals that the Commission carefully weighed the evidence and arguments supporting and opposing RTC's position and concluded, based upon Sprint witness Farrar's testimony, that, although Sprint's proposed interconnection would result in some small economic harm, any such harm would not constitute an undue economic burden on RTC. In doing so, the Commission noted that predicting the economic impact of competitive entry on RTC with any certainty was difficult. Nevertheless, the Commission found Sprint witness Farrar's testimony regarding the potential losses that RTC would suffer to be credible, even considering RTC's challenges to it. In support of its conclusion, the Commission further noted that RTC's effective management and loyal customers could mitigate the economic effects of the proposed competitive entry. According to the Public Staff, RTC has not offered any reason to depart from these conclusions. Therefore, the Public Staff opined that the Commission should not revise its decision in Finding of Fact No. 5 that Sprint's request for a partial termination of RTC's rural telephone company exemption is not unduly economically burdensome and is consistent with Section 254 of the Act (other than subsections (b)(7) and (c)(1)(D) thereof).

REPLY COMMENTS

RTC: In its Reply Comments, RTC reiterated its argument that Sprint had failed to prove that RTC will not suffer an undue economic burden if RTC's exemption is terminated and if Sprint and TWC are allowed to compete for customers in RTC's service territory. Further, RTC reiterated that the Sprint/TWC business model, which will only provide a competitive choice to RTC's customers residing within reach of TWC's facilities, will not provide a competitive choice to those RTC customers who do not reside within the Town of Liberty (Liberty). As a result, RTC contends that the Sprint/TWC business model does not satisfy the goal of universal service required by the Act.

STAR: Star did not file Reply Comments.

DISCUSSION

In its comments, RTC objected to the Commission's finding that partially terminating RTC's rural exemption is not unduly economically burdensome. According to RTC, the Commission failed to give adequate weight to the evidence and analysis that Randolph presented that allegedly illustrated the extent of Sprint's understatement of the line loss which RTC would suffer from competitive entry by Sprint/TWC in part of its service area. RTC submitted that the evidence in the record requires the Commission to find that terminating RTC's rural exemption in order to allow the offering of TWC's Digital Phone service in the Liberty imposes an undue economic burden on RTC because Sprint cannot forecast with any certainty RTC's line and revenue losses resulting from the provision of service by Sprint/TWC.

In addition, RTC again contended that Sprint has an obvious incentive to understate the revenue losses that RTC will sustain if Sprint is allowed to facilitate TWC's deployment of Digital Phone service in Liberty. Because of the significance of Sprint's projections in resolving this issue, RTC reiterated its discussion of the evidence and argument in its post-hearing brief on this point. RTC mainly contested Sprint witness Farrar's line loss estimates. According to RTC, witness Farrar's projected line losses for RTC are dramatically less than the line losses shown by Sprint/TWC's success in taking ILECs lines in North Carolina and dramatically less than the 3%, 8%, and 15% three year penetration rates that Sprint projected for itself in Ohio proceedings. If TWC were to achieve the penetration that Sprint projected in Ohio, RTC contends that it would be operating at a significant loss. RTC further explains that, based on its revenues for the 12-month period ending December 2006, as shown on Corrected Farrar Exhibit RGF-2, and applying Sprint's Ohio projections, RTC's revenues would be reduced in year one and reduced again by an additional factor in year two. In year three, RTC would have a significant revenue loss. In computing the above figures, RTC factored in the savings that it would realize from not having to pay taxes on the revenues it did not receive as a result of losing lines to Sprint/TWC. According to RTC, if the Commission had properly considered the aforementioned information and given the appropriate weight to the evidence and analysis presented by RTC, the Commission would have been precluded from allowing Sprint's request to terminate RTC's rural exemption. For the reasons advanced by RTC, Star and NCTA generally agree with RTC's position. Both the Public Staff and Sprint disagree.

In reviewing the argument and analysis that RTC presented in support of its request that the Commission reconsider the decision partially terminating RTC's rural exemption, it is noteworthy that RTC did not dispute the Commission's conclusion that the essential question which must be resolved in determining the undue economic burden issue is the extent to which the Commission should accept or reject witness Farrar's testimony on the line and revenue loss issues. In its objections, as in its post-hearing brief, RTC assails Sprint witness Farrar's projections of RTC's line and revenue losses as understated. RTC contended that the Commission failed to adequately weigh the evidence showing the extent of the line losses that RTC would suffer from competitive entry in part of its service area. The Commission disagrees.

A review of the *RAO* reveals that the Commission carefully weighed and considered very similar arguments advanced in RTC's post-hearing brief, as well as the arguments presented in the post-hearing briefs and the proposed orders of Sprint and the Public Staff.[1] In particular, the Commission carefully reviewed witness Farrar's testimony in the *RAO* and noted that RTC challenged his credibility on a number of different grounds. In making the decision to permit the rural exemption to be partially terminated and to allow Sprint/TWC to compete in the RTC service territory, the Commission simply was not persuaded that witness Farrar's testimony contained the serious flaws that RTC alleged. For example, witness Farrar's line loss calculations were based on actual TWC penetration rates and Sprint's experience in other markets. The Commission continues to believe that these figures are more likely to reflect the impact of competitive entry in RTC's market using the Sprint/TWC business model than the penetration rates that Sprint projected in Ohio and the penetration rates that TWC achieved in more urban portions of North Carolina. The Commission stated that, "[d]espite the inherent uncertainties that exist when projections are used instead of actual data, the Commission finds, after careful consideration of the evidence in the record, that witness Farrar's evidence on this point was persuasive . . . ."[2]

In making this finding, the Commission acknowledged that the record did not allow it to precisely analyze the impact that the projected line losses would have on RTC's expenses, so that it could not determine the exact impact of this omission from RTC's analysis on the projected returns set forth in its post-hearing brief. The Commission also noted that RTC's projections did not address credible line loss data showing that Sprint's projected first year penetration rates were consistent with the first year penetration rates that Sprint actually experienced when providing local services in a sizable number of rural markets across the nation using the Sprint/cable business model. In sum, the Commission found that RTC's projections and other challenges to witness Farrar's testimony did not undermine the credibility of his analysis.[3] In fact, after considering the entire record, the Commission found witness Farrar's quantitative analysis of this and other issues sufficiently credible to conclude that RTC would not be unduly economically burdened and that the goal of preserving universal service would not be undermined by Sprint/TWC entry into RTC's market as a competitor.

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[1] *RAO*, at pp. 17-21.

[2] *RAO*, at p. 17.

[3] *See State ex rel. Utils. Comm'n. v. Duke Power Co.*, 305 N.C. 1, 21, 287 S.E.2d 786, 798 (1982) (explaining that the Commission may weigh the credibility of the witnesses before it).

The record also reflects that these conclusions were supported by other less quantifiable but equally persuasive factors. For instance, the Commission found it compelling that Sprint was only requesting a partial, instead of a total, waiver of RTC's exemption. In the Commission's opinion, this limitation on the scope of the request lessened the potential economic impact of Sprint's request to compete in RTC's market. Similarly, the evidence also included strong customer statements supportive of RTC's service. These statements, in addition to demonstrating that RTC is a well-managed company, indicate that its customers may be resistant to a competing supplier's efforts to woo them away from RTC. The Commission properly interpreted this evidence of customer loyalty as providing some protection to RTC from any economic losses resulting from a Commission decision allowing Sprint and TWC to compete with RTC. Furthermore, the record reflected that RTC had proposed and the Commission had approved a price regulation plan for RTC. Thus, RTC has the regulatory flexibility needed to respond quickly to competition as it develops. Lastly, the Commission reminds RTC that the ratchet clause of G.S. 62-133.5(c) allows it to petition to revise its price regulation plan without incurring any risk that the Commission will modify the plan in a manner that is unsatisfactory to RTC. This, too, has the potential to minimize any potential adverse impact resulting from Sprint's entry into RTC's market.

These quantitative and qualitative factors collectively suggested and suggest by the greater weight of the evidence that the economic burden suffered by RTC if the rural exemption is terminated and Sprint/TWC are allowed to compete for customers in RTC's service territory would not be undue. In the Commission's view, RTC has offered no compelling new evidence, argument or analysis which would require the Commission to revise Finding of Fact No. 5 in whole or in part. RTC's request that Finding of Fact No. 5 be revised in conformity to its objections should therefore be denied.

CONCLUSIONS

The Commission reaffirms its conclusion that Sprint's request for a partial termination of Randolph's rural telephone company exemption is not unduly economically burdensome and is consistent with Section 254 of the Act (other than subsections (b)(7) and (c)(1)(D) thereof).

<u>ISSUE NO. 1 - MATRIX ISSUE NO. 1</u>: Is Randolph exempt from interconnecting with Sprint pursuant to the requirements of Sections 251(a) and (b)?

<u>FINDING OF FACT NO. 6</u>: Sprint's request for a partial termination of Randolph's rural telephone company exemption should be granted, and Randolph should be required to comply with the provisions of Sections 251(c)(1) and (2) of the Act.

INITIAL COMMISSION DECISION

The Commission concluded that it is under no illusion that it is able to accurately predict the future. The Commission stated that it can merely make the best possible predictive judgment given the evidence in the record. Over the long term, RTC's survival and profitability will depend on the skill and insight of its management, as well as many other factors that cannot now be foreseen. The Commission noted that, in the immediate future, it does not believe that the interconnection requested by Sprint, and the resulting competition between RTC and Sprint and Time Warner, will place an undue economic burden on RTC or significantly interfere with the availability of universal service to RTC's customers. Accordingly, the Commission concluded that Sprint's request for partial termination of RTC's exemption under Section 251(f)(1) of the Telecommunications Act of 1996 (Act) from the obligations of Sections 251(c)(1) and (2) should be granted.

MOTIONS FOR RECONSIDERATION

SPRINT: Sprint did not object to this Findings of Fact.

RTC: RTC also objected to Finding of Fact No. 6, which finds that Sprint's request for a partial termination of RTC's rural telephone company exemption should be granted. In this Finding of Fact, the Commission undertook to strike a balance between the risk of economic harm to RTC and "state and national policy favoring competitive telecommunications services." RTC asserts that the Commission did not strike the proper balance between the relevant interests, as the record established that less than half of RTC's customers would be able to elect to receive service through the Sprint/TWC business model, i.e., less than half of RTC's customers would have "customer competition and choice in telecommunications service" while the majority would have no competitive choice and will be left to bear the eventual and unavoidable consequences of RTC's line losses in Liberty. Further, RTC objects to the Commission's conclusion that, "in this case . . . on balance, the state and national policy favoring customer competition and choice in telecommunications service must take precedence over the risk that Randolph may suffer some limited economic harm if Sprint and Time Warner are allowed to compete with Randolph . . . ." (emphasis in original) (*RAO* p. 20). RTC believes that the Commission's statement that the policy favoring competition "must take precedence" suggests that the Commission failed to appreciate the latitude afforded to it by Section 251(f)(1) of the Act, which provides that rural telephone companies are to remain exempt from competition if an undue economic burden or adverse impact on universal service would result from competitive entry. Finally, RTC objected to the Commission's failure to even address the public interest that would be served if the Commission conditioned termination of Randolph's rural exemption on a requirement that Sprint/TWC be required to meet the requirements for designation as an eligible telecommunications carrier in all of RTC's service area, as provided for in Section 253(f).

NON-PARTY COMMENTS

STAR: Star asserted that the Commission's decision in this matter ignored Section 253(f) of the Act because it did not require Sprint to assume the same universal service obligations as RTC while allowing Sprint's request to interconnect. According to Star, because the Sprint/Time Warner business model focuses on providing service in the more attractive area of RTC's service territory, i.e., Liberty, the effect of the *RAO* is to deprive the customers in the more rural areas of RTC's service territory of the benefits of competition and doom those same customers to be second class telecommunications consumers. While Star recognized that most new entrants generally choose to serve the more densely populated and thus more attractive areas when entering the market, Star questions whether it is wise public policy to allow such an approach in a demonstrably rural market like RTC's.

INITIAL COMMENTS

SPRINT: Sprint commented that RTC objected to Finding of Fact No. 6 by arguing that the Commission gave inordinate weight to the policy goal of furthering customer competition and choice. Sprint maintains that the primary purpose of the Act was to bring competitive choice to consumers and that the Section 251(f)(1) exceptions to this goal enjoyed by the rural ILECs are secondary and temporary in nature. Therefore, according to Sprint, the Commission is in a much better position to weigh policy goals than RTC, an interested party, and the Commission was correct in giving considerable weight to the public interest in affording consumers a choice, especially in rural areas.

PUBLIC STAFF: With regard to Finding of Fact No. 6, the Public Staff stated that the Commission should not revise this finding. The Public Staff noted that RTC specifically objected to this finding on the ground that it is not in the public interest for Sprint/TWC to be allowed to "cream skim" RTC's more profitable and easily-served customers in Liberty. RTC argues that, while these customers may have additional choice through this competition, the majority of RTC's customers will have no additional choice as a result of Sprint's request for interconnection. Moreover, RTC argues, these same customers must face the economic and service consequences of Sprint/TWC's competition with RTC in Liberty. Thus, RTC objects to the Commission's decision because the Commission did not condition termination of RTC's rural exemption on Sprint/TWC having to meet the requirements for designation as an eligible telecommunications carrier in all of RTC's service area, as provided for in Section 253(f) of the Act. In its comments, however, the Public Staff stated that RTC advanced those same essential arguments in its post-hearing brief and that RTC had offered no compelling reason for the Commission to revisit its decision. Therefore, the Public Staff maintains that the rationale behind Finding of Fact No. 6, which states that Sprint's request for a partial termination of RTC's rural telephone company exemption should be granted, is sound.

REPLY COMMENTS

RTC: In its Reply Comments, RTC reiterated its arguments that Sprint has failed to prove that RTC will not suffer an undue economic burden if RTC's exemption is terminated and Sprint and TWC are allowed to compete for customers in RTC's service territory. Further, RTC reiterated that the Sprint/TWC business model will only provide a competitive choice to RTC customers residing within reach of TWC's facilities and will not provide the same choice to those RTC customers who do not reside within Liberty and that this outcome is contrary to the universal service goals established by the Act.

STAR: Star did not file Reply Comments.

DISCUSSION

RTC contends that the Commission inappropriately found that the policy goal of favoring competition outweighed the evidence of undue economic burden to RTC in Finding of Fact No. 6. RTC's argument centers on the identity of the customers that would be offered service under Sprint/TWC's business model. According to RTC, the Commission's decision allows

Sprint to "cream skim" by electing to offer service to RTC's most profitable and easily served customers in Liberty. It argues that the record established that fewer than half of RTC's customers would be offered that service. Consequently, RTC argues that the majority of its customers will not enjoy the benefits of competitive telecommunications services if Sprint/TWC entry is allowed. Additionally, those customers will be left to bear the consequences of the loss of customers that RTC will sustain in Liberty. The Commission thus erred, according to RTC, in finding that the policy favoring customer competition requires resolving the issue for Sprint.

RTC further contends that the Commission failed to address the public interest and universal service goals that would be served if the Commission conditioned terminating RTC's rural exemption on a requirement that Sprint and TWC meet the requirements for designation as an eligible telecommunications carrier throughout RTC's service area, as provided for in Section 253(f). The imposition of this condition would allow all of RTC's customers an opportunity to choose between competitors, while foreclosing Sprint's "cream skimming."

As with its objection to Finding of Fact No. 5, RTC has presented no new compelling argument or evidence requiring the Commission to revise Finding of Fact No. 6. RTC made essentially the same arguments in its post-hearing brief regarding "cream skimming" and universal service that it advances now.[1] The Commission carefully considered each of those arguments in the *RAO*. After carefully weighing the evidence and the arguments advanced by all parties, the Commission found that the policy of fostering competition takes precedence over the risk that RTC may suffer some limited economic harm if Sprint/TWC is allowed to compete given the facts of this case. The Commission believes that this conclusion is consistent with the following FCC policy pronouncement articulated in Paragraph 1263 of the First Report and Order:

> Congress generally intended the requirements in Section 251 to apply to carriers across the country, but Congress recognized that in some cases, it might be unfair or inappropriate to apply all of the requirements to smaller or rural telephone companies. We believe that Congress intended exemption, suspension, or modification of Section 251 requirements to be the exception rather than the rule, and to apply only to the extent, and for the period of time, that policy considerations justify such exemptions, suspension, or modification. We believe that Congress did not intend to insulate smaller or rural LECs from competition, and thereby prevent subscribers in those communities from obtaining the benefits of competitive local exchange.

Moreover, the Commission notes that the Act was adopted in 1996, i.e., twelve years ago. Since that time, RTC, an admittedly small and rural carrier, has been exempt from the full impact of the competition that Congress clearly intended to introduce into the local telecommunications market. As evidenced by the preceding policy statement, RTC's exemption from the pro-competitive provisions of the Act was never intended to be permanent; instead, its exemption was always intended to be temporary. In this proceeding, Sprint presented evidence that RTC will not be unduly economically burdened by Sprint's entry into the market served by RTC which the Commission found to be persuasive. Despite the arguments that RTC has advanced in

[1] *RTC's Post-Hearing Brief, pp. 32-42.*

opposition to the *RAO*, the Commission is simply not persuaded that a different conclusion is warranted based upon this "new evidence and projections." Thus, RTC's request to revise Finding of Fact No. 6 is hereby denied.

As an alternative, RTC also argued that the Commission should condition the termination of RTC's rural exemption upon a concomitant determination that Sprint/Time Warner should be required to pursue and receive designation as an eligible telecommunications carrier in all of RTC's service area as provided in Section 253(f) of the Act before it is permitted to compete for customers with RTC. According to RTC, the imposition of such a condition would further the state and national policy favoring customer competition in telecommunications service for all, not just a minority, of RTC's customers. This position is supported by Star and opposed by Sprint and the Public Staff. The *RAO* did not specifically address this contention.

Section 253(f) states that:

> It shall not be a violation of the section for a state to require a telecommunications carrier that seeks to provide telephone exchange service or exchange access in a service area served by a rural telephone company to meet the requirements in section 214(e)(1) for designation as an eligible telecommunications carrier for that area before being permitted to provide such service.

This provision of the Act permits, but does not require, the Commission to condition Sprint/TWC's ability to provide telephone access service in RTC's service area on Sprint/TWC's meeting the requirements set out in Section 214(e)(1) for designation as an eligible telecommunications carrier throughout RTC's entire service area if the Commission finds that such designation would be in the public interest. See 47 U.S.C. 214(e)(2). RTC argues that it is in the public interest to require such designation in this case because such action would further the state and national policy favoring customer competition in telecommunications service by ensuring that customers in all, not just a small part of, RTC's service territory have an opportunity to choose between competitors, while forcing Sprint/Time Warner to do more than to "cream skim" RTC's easiest to serve and most profitable customers. RTC's argument, however, is predicated upon this Commission's rejection of the analysis and testimony provided by witness Farrar that Sprint/TWC will offer competitive service to all business and residential customers for whom TWC facilities are available, a group of customers that use approximately two-thirds of Randolph's access lines. See Revised RGF Exhibit 7.

RTC again argues that Farrar's testimony in this regard simply is not credible for a number of reasons. Chief among these reasons is RTC's assertion that witness Farrar's evidence on this point is not credible because witness Farrar has no personal knowledge of the location of TWC facilities or the number of RTC customers that would be able to receive service from TWC. This is the same argument that RTC made at the hearing and its post trial brief. The Commission was not persuaded by this argument then and is not persuaded by it now. In the Commission's judgment, the testimony provided by witness Farrar that customers using more than two thirds of RTC's access lines could potentially be provided a competitive choice is simply more credible than the evidence provided by RTC. Sprint will offer competitive service to all business and residential customers for whom TWC facilities are available. Generally speaking, a CLP, such as Sprint, cannot and should not be asked, expected or required to do any more than it is capable of doing, i.e., offer service to all within its collective serving footprint. This is consistent with the general policy articulated by Congress, which favors the removal of barriers to entry in the telecommunications market and permits a CLP to offer a competitive alternative to a limited portion of an ILEC's market. See 47 U.S.C. 253. This fosters competition and ultimately provides consumers with alternatives to the monopoly market that existed prior to the adoption of the Act.

RTC's proposal, though permitted by Section 253, is inconsistent with the pro-competitive focus of the Act and greatly expands a CLP's service obligation to include carrying out eligible telecommunications carrier responsibilities for a rural ILEC's entire service area. Such a condition should only be adopted if and when it is clear that such a requirement is in the public interest. RTC, as the proponent of this proposal, bears the burden of presenting detailed evidence to justify a Commission order that deviates from the general policy of permitting a CLP to define its service territory as it wishes. In the Commission's opinion, the scant (and previously rejected) evidence and lengthy argument presented by RTC in support of this position is insufficient for the Commission to conclude by the greater weight of the evidence that the public interest would be served by requiring Sprint/TWC to be designated an eligible telecommunications carrier for RTC's entire service area as a precondition for being allowed to make competitive entry. Thus, RTC's alternative request that Sprint/TWC be required to obtain designation as the eligible telecommunications carrier throughout RTC's service territory is hereby denied.

CONCLUSIONS

The Commission reaffirms its conclusion that Sprint's request for a partial termination of Randolph's rural telephone company exemption should be granted and that Randolph should be required to comply with the provisions of Sections 251(c)(1) and (2) of the Act.

<u>ISSUE NO. 2 – MATRIX ISSUE NO. 3</u>: Is Sprint entitled to interconnect and exchange traffic with RTC pursuant to Section 251(a) and Section 251(b) of the Act as a wholesale telecommunications provider of services to other carriers, including providers of VoIP telephony service?

<u>FINDING OF FACT NO. 7</u>: Sprint is entitled to interconnect and exchange traffic with Randolph pursuant to Sections 251(a) and (b) of the Act as a wholesale telecommunications provider of services to other carriers, including Voice over Internet Protocol (VoIP) telephony service.

INITIAL COMMISSION DECISION

The Commission concluded that Sprint is entitled to interconnect and exchange traffic with RTC pursuant to Sections 251(a) and (b) of the Act as a wholesale telecommunications provider of services to other carriers, including entities providing VoIP telephony service. The Commission noted that the proper resolution of this issue hinges on the appropriate interpretation of the FCC's recent Order in *Time Warner Cable*, WC Docket No. 06-55, DA 07-709 (released

March 1, 2007) (*Time Warner Order*). The Commission noted that the *Time Warner Order*, issued by the FCC's Wireline Competition Bureau, addressed the very same business model that Sprint is proposing to use in the instant case. In the *Time Warner Order*, Sprint and Time Warner were combining to offer VoIP service to end-user customers, with Sprint providing end office switching, PSTN interconnectivity, functions relating to the numbering system, domestic and international toll service, operator service, directory assistance, and back-office functions, and with Time Warner providing "last-mile" facilities, sales, billing, customer service and installation. The ILECs involved in that case argued that Sprint was acting in a wholesale capacity and could not be considered a telecommunications carrier. However, the FCC rejected the ILECs' position and held that Sprint, as a wholesale provider of telecommunications, was a "telecommunications carrier" entitled to interconnect with the ILECs regardless of whether the VoIP service being provided to end-users was considered to be a telecommunications service or an information service. The Commission concluded that the *Time Warner Order* was directly on point and conclusively established that Sprint was entitled to interconnect and exchange traffic with Randolph pursuant to the Act as a wholesale telecommunications provider of services to other carriers.

MOTIONS FOR RECONSIDERATION

SPRINT: Sprint did not object to this Finding of Fact.

RTC: RTC stated in its Objections to this Finding of Fact that, contrary to the Commission's conclusion that Sprint is a telecommunications carrier, many of the services cited on p. 23 of the *RAO* are not "telecommunications services" and thus do not support classifying Sprint as a "telecommunications carrier." Since TWC's retail service is not a telecommunications service, Sprint's provision of local number portability and other services does not constitute the provision of telecommunications services as defined in the Act. Randolph also maintained that, according to 47 CFR Section 51.100, which addressed the exchange of traffic between two carriers pursuant to an interconnection agreement, a carrier obtaining interconnection must be transmitting telecommunications traffic. Only after this initial criterion has been satisfied is a telecommunications carrier entitled to use excess capacity to exchange information traffic. The *Time Warner Order* recognized that parties such as Sprint may not obtain interconnection pursuant to Section 51.100 solely for the purpose of providing non-telecommunications purposes. Thus, Sprint must exchange local telecommunications service traffic over the requested trunks and facilities before it can use the same interconnection agreement to exchange information service traffic generated by TWC.

RTC also asserted that the FCC had concluded that there are some services or functions that are "incidental and adjunct to common carrier transmission," including local number portability, central office space for collocation, and certain billing and collection services. These services, according to the FCC, "should be treated for regulatory purposes in the same manner as the transmission services underlying them…." *Bright House Networks v. Verizon California, Inc.*, FCC File No. EB-08-MD-002, Para. 31 (June 23, 2008) (*Bright House*). The FCC indicated that these adjunct-to-basic services are vital to the provision of telecommunications services. RTC contended that it logically follows that, when the underlying retail service is *not* a telecommunications service, these adjunct-to-basic services supporting the provision of non-telecommunications services should be treated as non-telecommunications services. RTC asserted that "[t]here is no dispute" that TWC will be offering only a retail interconnected VoIP service, which it defines as a non-telecommunications service. Thus, on the basis of the representation that TWC's retail service is not a telecommunications service, Sprint's provision of local number portability and other services incidental to this transmission of such non-telecommunications traffic does not constitute telecommunications service.

NON-PARTY COMMENTS

STAR: Star did not discuss this Finding of Fact in its comments.

INITIAL COMMENTS

SPRINT: Sprint stated the Commission's interpretation of the *Time Warner Order* and the resulting conclusion that Sprint is a provider of telecommunications services entitled to interconnect and exchange traffic with Randolph pursuant to the Act was correct and is consistent with the way in which many jurisdictions across the country have decided the same issue.[1]

PUBLIC STAFF: The Commission should not revise Finding of Fact No. 7. RTC's argument that the services that Sprint is providing—namely, end office switching, PSTN interconnectivity, numbering, domestic and internal toll, operator, and directory assistance services—are not telecommunications services is incorrect. RTC has characterized these services as incidental or adjunct to common carrier transmission. According to RTC, since TWC provides "non-telecommunications" services, the adjunct services do not support telecommunications services themselves, and thus cannot be considered telecommunications services.

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[1] Specifically, Sprint cited to *Sprint Communications Company LP v. Nebraska Public Service Commission et. al.*, Memorandum and Order, Case No. 4:05CF3260 (D.C. NE, September 7, 2007); *Consolidated Communications of Fort Bend Company et al. v. The Public Utility Commission of Texas, et al.*, Memorandum Opinion and Order, Cause No. A-06-CA-825-LY (W.D. TX., July 24, 2007); *Berkshire Tel. Corp. v. Sprint, No. 05-CV-6502, 2006 WL 3095665* (W.D.N.Y., October 30, 2006); *Iowa Telecommunications Services, Inc. d/b/a Iowa Telecom v. Iowa Utilities Board, Utilities Division, Department of Commerce; John Norris, Diane Munns, and Curtis Stamp, in their Official Capacities as Members of the Iowa Utilities Board and not as individuals, and Sprint Communications LP, d/b/a Sprint Communications Company, LP* 4:06cv0291 JAJ, Order (April 15, 2008)(*Iowa Telecom*); *Application of Sprint Communications Company LP to Expand Certification as an Alternative Telecommunications Utility*, Final Decision, Pub. Serv. Comm'n of Wisc. Docket No. 6055-NC-103 (May 9, 2008); *Application of Sprint Communications Company LP for Approval of the Right to Offer, Render, Furnish or Supply Telecommunications as a Competitive Local Exchange Carrier to the Public in the Service Territories of Alltel Pennsylvania, Inc, Commonwealth Telephone Company, and Palmerton Telephone Company*, Penn. Pub. Util. Comm'n, A310183F0002AMA, A-310183F0002AMB, A-310183F0002AMC, Opinion and Order (December 1, 2006); *In the Matter of the Application and Petition in Accordance with Section II.A.2.b of the Local Service Guidelines Filed by Buckland Telephone Company, Minford Telephone Company, The Glandorf Telephone Company, Inc., and Sycamore Telephone Company*, Finding and Order, Pub. Util. of Ohio Case Nos. 06-884-TP-UNC, 06-885-TP-UNC, 06-886-TP-UNC and 08-884-TP-UNC (Nov. 21, 2006; *Harrisonville Telephone Company et al. v. Illinois Commerce Commission et al.*, Memorandum and Order, Civil No. 06-73-GPM (S.D. Ill., September 5, 2007); and *In the Matter of Bright House Networks, LLC, et al. v. Verizon California, Inc. et al.*, Memorandum Opinion and Order, File No. EB-08-MD-002 (released June 23, 2008).

The Commission correctly construed the *Time Warner Order* by finding that RTC could not refuse to interconnect with Sprint because Sprint was providing a wholesale service rather than a retail services. If Sprint offers the above-named services through its interconnection with RTC, it may then also offer information services, without limitation as to the relative amounts of the two types of services.

RTC's reliance on *Bright House* is also misplaced. RTC has argued that the above-named services are supporting the provision of VoIP service instead of telecommunications service. However, *Bright House* actually supports the Commission's decision. In *Bright House* the defendants were ILECs, while the complainants—including TWC—were providing facilities based voice services to retail customers *using VoIP*. As in the instant case, TWC and the other complainants provided VoIP services by relying on wholesale CLECs to interconnect with ILECs and to provide transmission services, local number portability, and other functionalities. As in the instant case, TWC relied upon Sprint for this service. Thus, in very similar circumstance, the FCC found that "adjunct-to-basic" services were telecommunication services.[1]

Even setting aside *Bright House*, the unresolved regulatory status of VoIP service should not change the Commission's decision. In the *Time Warner Order*, at para. 15, the FCC stated that "[t]he regulatory classification of the service provided to the ultimate end user has no bearing on the wholesale provider's rights as a telecommunications carrier to interconnect under section 251. As such, we clarify that the statutory classification of a third-party provider's VoIP service *is irrelevant to the issue of whether a wholesale provider of telecommunication service may seek interconnection under section 251(a) and (b).*" (Emphasis added). Furthermore, several federal courts have reviewed the Sprint/cable company business model and have found that Sprint was providing telecommunications services under the *Time Warner Order*, most recently in the *Iowa Telecom* case cited in the footnote above. Evolving case law bolsters the Commission's conclusion in the *RAO* on this issue.

REPLY COMMENTS

RTC: RTC filed no Reply Comments as to this issue.

DISCUSSION

In the Commission's original decision on this issue, it relied on the *Time Warner Order* and concluded that Sprint was indeed providing certain telecommunications services to support the VoIP services offered by TWC. A plain reading of the *Time Warner Order* establishes that

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[1] See, *Bright House* at Paras. 31-32. "Number portability, however, is a wholesale input that is a necessary component of a retail telecommunications service. We have previously found that services or functions that are 'incidental or adjunct to common carrier transmission service'—i.e., they are 'an integral part of, or inseparable from, transmission of communications'—should be classified as telecommunications services." (Para. 31). Also, since "LNP [local number portability] similarly constitutes such an [please check the quote to see if this change is appropriate] 'adjunct to basic' service. Verizon's provision of LNP is a vital part of the telecommunications services that it provides to the Competitive Carriers.... Moreover, implementing LNP requires Verizon to be involved in properly switching and transmitting calls to the new carrier—these are unquestionably 'telecommunications' functions."

only a bare minimum of telecommunications services need to be offered by Sprint or a similarly situated carrier in order for the arrangement to support a request for interconnection. As noted by the Public Staff and Sprint, evolving case law bolsters the Commission's conclusion concerning the manner in which the *Time Warner Order* should be construed, most recently and notably the *Iowa Telecom* case.

RTC attempted to salvage its position by advancing a new line of argument. RTC cited to the *Bright House* case for the proposition that the Sprint services were supporting VoIP services rather than telecommunications services. However, as the Public Staff pointed out, the opposite is more nearly the case. In a factual situation similar to the instant case, the FCC found that the "adjunct-to-basic" services were telecommunications services.

Accordingly, the Commission reaffirms its original decision on this issue for the reasons generally set forth by Sprint and the Public Staff above.

CONCLUSIONS

The Commission reaffirms its conclusion that Sprint is entitled to interconnect and exchange traffic with RTC pursuant to Section 251(a) and (b) of the Act as a wholesale telecommunications provider of services to other carriers, including entities providing VoIP telephony service.

FINAL ISSUE - PROCEDURAL OBJECTION REGARDING IMPLEMENTATION SCHEDULE:

At the end of its Objections to the *RAO* in this case, RTC moved beyond the numbered issues and objected to the alleged failure of the Commission to establish a timeline for negotiations as required by Section 251(f)(1)(B). Section 251(f)(1)(B) provides, in pertinent part, that, "[u]pon termination of the exemption, a State commission shall establish an implementation schedule for compliance with the request that is consistent in time and manner with Commission regulations."

RTC noted that the Commission had addressed certain issues by directing the parties, with the assistance of the Public Staff, to negotiate various matters with respect to Findings of Fact 8, 12, and 13. RTC stated that the parties have had only limited negotiations because of the outstanding issue of the termination of the rural exemption. RTC contended that, to the extent the Commission now directs the parties to negotiate further, the parties are entitled to an implementation schedule that is "consistent in time and manner" with FCC regulations, yet the Commission has failed to establish such a schedule.

RTC further reiterated its view that it had no duty to negotiate with Sprint prior to the termination of the rural exemption or even to submit to arbitration. According to RTC, there have been no voluntary negotiations between the parties and, thus, there are no "open issues" for arbitration. These contentions, RTC said, were supported by *Sprint Communications Company L.P. v. Public Utility Commission of Texas,* Slip Copy 2006, WL 4872346, No. A-05-CA-065-SS

(W.D. Tex. 2006) and *Coserve LLC v. Southwestern BellTel. Co.*, 350 F. 3d 482, 487 (5th Circ. 2003).

Star and NTCA echoed RTC's arguments.

In Response, **Sprint** disagreed with RTC's claim that the Commission had failed to establish an implementation schedule in the *RAO*. While in some situations it may be necessary for the Commission to establish a more detailed implementation schedule that builds in a substantial time period for the parties to conduct negotiations, such is not the case in this proceeding. There have already been considerable negotiations between the parties both before and after the filing of Sprint's arbitration petition, and most of the necessary contract language has either been resolved through negotiation or through arbitration. For example, Sprint noted that RTC had raised thirty-seven additional issues for negotiation in its April 10, 2007 Preliminary Response. All of these issues were either negotiated to resolution or incorporated into the Revised Joint Arbitration Issues Matrix filed by the parties on January 23, 2008, pursuant to the Commission's July 23, 2007, Order Scheduling Hearing and Establishing Procedures. Thus, the only remaining "implementation" that is necessary in this docket is the parties' execution of and subsequent compliance with the Composite Agreement. The Commission provided for this in its *RAO* by setting a deadline for the filing of the parties' Composite Agreement—which was thereafter suspended pending a ruling on RTC's objections. A new deadline will go into effect after these objections have been resolved. Such an order will presumably allot a limited amount of time for the parties and Public Staff to resolve the remaining issues. At that point, all of the "implementation" issues will have been addressed.

The Public Staff argued that, based on all of the circumstances in this case, the establishment of a more detailed schedule to implement the approved interconnection is unnecessary. The Commission has allowed only a partial termination of RTC's exemption and has also suspended the deadline for the filing of the Composite Agreement. The Commission has not erred in its decision.

In Reply to the Responses, **RTC** asserted that the circumstances were such that RTC was forced to attempt to defend its rural exemption and, at the same time, to arbitrate the rates, terms and conditions for interconnection. Because of this dual track procedure, RTC was not able to fully consider all the potential implications of the proposed interconnection agreement. It is RTC's view that, in accordance with the procedure established by Section 251(f)(1)(B), the Commission must first terminate the rural exemption, and, if it chooses to do so, it may then direct the parties to negotiate upon a schedule that is "consistent in time and manner with the [FCC] regulations." The *RAO*'s proposed Findings of Fact 8 through 13 determine the content of the agreement and provide the Public Staff with a role in resolving open issues.

DISCUSSION

RTC has objected that the Commission has not complied with the implementation scheduling requirement of Section 251(f)(1)(B), which provides, in pertinent part, that "[u]pon termination of the exemption, a State commission shall establish an implementation schedule for compliance with the request that is consistent in time and manner with Commission regulations."

RTC makes particular reference in its September 29, 2008, Objections and in its November 14, 2008, Reply Comments, to Findings of Fact 8 through 13, as those in which the Commission mandated further negotiations.

The Commission would first note that Section 251(f)(1)(B) simply requires the state commission to "establish an implementation schedule for compliance with the request that is *consistent in time and manner with Commission regulations.*" (Emphasis added). However, nowhere in its filings does RTC actually cite to any pertinent FCC regulation that sets out a "time and manner" for implementation in the way that RTC asserts is required. Instead, RTC laments that the dual track procedure by which this arbitration has been conducted—i.e., consideration of lifting the exemption and consideration of the substantive matters at issue between the parties in the same proceeding—left it without time to consider all the implications of the proposed interconnection agreement. RTC implies that this procedural choice by the Commission was illegitimate. RTC's apparent view is that the exemption question must, temporally and procedurally, be examined and ruled upon first, and *then* the parties are to negotiate. It is unclear what timelines that RTC has in mind, but the thrust of RTC's arguments would seem to imply use of the timelines *and procedures* set forth in Section 252(a) and (b) of the Act. The Commission does not believe that Section 251(f)(1)(B)'s language determines whether it is appropriate to consolidate proceeding or requires adherence to Section 252(a) and (b) timelines after the arbitration has already been conducted.

The Commission notes that, in fact, the parties have negotiated, and will negotiate on certain issues pursuant to the *RAO*. Based upon the record before us, it is clear that the parties have already engaged in substantive negotiations prior to the hearing pursuant to Section 252. The only question this objection raises is whether the Commission has complied with the implementation schedule requirement of Section 251(f)(1)(B). The Commission has prescribed the implementation schedule relative to the lifting of the exemption at various places within the body of the *RAO* and will provide a further modification of the implementation schedule in this order ruling on objections. The Commission has thus complied with that requirement, and RTC has made no showing, by citation to relevant FCC rules or otherwise, that the Commission has not.

CONCLUSIONS

The Commission has provided by this Order an implementation schedule compliant with the law.

IT IS, THEREFORE, ORDERED as follows:

1. That, in accordance with the Commission's January 24, 2001 and November 3, 2000 Orders issued in Docket No. P-100, Sub 133, Sprint and Randolph shall jointly file the required Composite Agreement by no later than Friday, January 30, 2009.

2. That the Commission will entertain no further comments, objections, or unresolved issues with respect to issues previously addressed in this arbitration proceeding.

3. That the Commission denies all objections to Findings of Fact Nos. 5, 6, and 7, thereby upholding and affirming its original decisions regarding these issues.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp123108.02

DOCKET NO. W-650, SUB 3
DOCKET NO. W-650, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-650, SUB 3

In the Matter of
Application by Springs Industries Inc., Post Office Box 70, Fort Mill, South Carolina 29715, for Authority to Discontinue Sewer Utility Service to Springfield Village Subdivision in Scotland County, North Carolina

DOCKET NO. W-650, SUB 4

In the Matter of
Application by Springs Industries Inc., Post Office Box 70, Fort Mill, South Carolina 29715, for Authority to Increase Rates for Sewer Utility Service in Springfield Village Subdivision in Scotland County, North Carolina

ORDER APPROVING STIPULATION, AUTHORIZING ABANDONMENT, AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On May 1, 2006, Springs Industries Inc. (Applicant or Springs), filed an application with the Commission seeking authority to discontinue sewer utility service to the 29 residential customers in Springfield Village Subdivision in Scotland County, North Carolina. In 1963, Springs acquired a textile plant adjoining Springfield Village, and thereafter provided water and sewer service to the textile plant and Springfield Village. In 1996, the water service to Springfield Village was transferred to the City of Laurinburg, leaving Springs providing sewer service to the textile plant and 29 residential customers. In December 2003, Springs closed the textile plant, resulting in Springs providing sewer service only to the 29 residential customers at a significant operating loss.

Subsequent to the filing of the application to discontinue service, the Public Staff and Springs have met with the customers, the City of Laurinburg, Scotland County, the North Carolina Division of Water Quality and others in an attempt to facilitate a permanent solution through applications for grant funding to Scotland County for the City of Laurinburg to extend sewer service to Springfield Village.

On February 6, 2007, Springs filed an application for a rate increase with a request for approval of emergency interim rates to limit the operating losses. Springs then existing rates were $6.00 minimum monthly charge for the first 3,000 gallons of usage, and $0.75 per 1,000 gallons usage for all over 3,000 gallons per month, which results in an average monthly bill of $6.56 based upon consumption of 3,753 gallons. The proposed interim rate was $75.00 per month flat rate, and the requested final rate was $247.00 monthly flat rate.

By Order dated March 5, 2007, the Commission consolidated the two dockets, established a general rate case, suspended the proposed rates pending further order of the Commission, approved the requested $75.00 interim rate subject to refund, and required customer notice. This Commission Order further provided that, should pursuit of sewer service from Laurinburg fail or stall such that the Applicant wished to pursue the requested $247 per month rate, the Applicant should notify the Commission so that another rate suspension order could be issued containing an appropriate time limit for filing testimony, a customer notice provision, and a hearing date. The Order further provided that should Springs desire in the future for the Commission to consider the Sub 3 abandonment application, Springs should provide written notification to the Commission. The Order also required Springs to file reports with the Commission every six months regarding the status of achieving a permanent solution.

By motion filed on October 26, 2007, Springs requested the Commission consider and grant Springs' request in the Sub 3 docket to abandon service. In support of the motion, Springs stated that the grant application process had resulted in only $128,000 of grant funding. This $128,000, in addition to $75,000 pledged by Springs, was insufficient to cover the total estimated $780,000 to $1,050,000 cost of extending service from the City of Laurinburg.

The October 26, 2007, motion stated that, even with the revenues received from the Springfield Village customers as a result of the Commission-approved $75.00 per month interim rates, Springs continues to experience significant financial losses in the operation of the sewer utility in Springfield Village. The Springs motion alleged that its requested $247 monthly rate would merely allow Springs to meet current expenses without taking into account costs for any major maintenance that will likely be needed in the next few years. The Springs motion further alleged that there is no reasonable probability of realizing sufficient revenues to meet its expenses.

By Order dated January 18, 2008, the Commission scheduled the application for abandonment for hearing in Laurinburg, North Carolina on March 27, 2008; established dates for the prefiling of testimony by Springs and the Public Staff; and required customer notice. By Order issued on February 11, 2008, the Commission moved the location of the hearing to another location in Laurinburg due to scheduling conflicts.

By agreement dated February 4, 2008, Springs and Scotland County agreed, in addition to other provisions, that Springs would provide up to $75,000 funding to be used by the County to facilitate installation of individual septic tank systems for the 29 customers, and the County would also facilitate obtaining executed releases and waiver of claims from the customers.

On February 19, 2008, a Petition of Support of Springs Industries Abandonment of Laurinburg Waste Water Treatment Plant, executed by 28 of the 29 customers or property owners, was filed with the Commission. This petition acknowledged Springs providing financial assistance for installing individual septic tanks at Springfield Village, and supported Springs' request to abandon the sewer utility service. Mr. J.D. Willis, the Chairman of the Scotland County Board of Commissioners, advised the Public Staff that Scotland County procured this executed petition.

On February 19, 2008, Springs and the Public Staff filed a stipulation with the February 4, 2008, Agreement attached as an exhibit. The stipulation requests that the Commission issue an order (1) approving the stipulation, (2) accepting for filing the Agreement between Springs and Scotland County, (3) ordering that Springfield Village customers be notified that they have until May 31, 2008, to install individual septic systems and that Springs' sewer service to Springfield Village would be abandoned and discontinued on June 30, 2008, or the date the last customer ceases to use the system, whichever occurs first, (4) requiring Springs to give written notice to the Commission when the last customer leaves the sewer system, (5) canceling the March 27, 2008, hearing and eliminating the requirement for filing of testimony, (6) approving the $75.00 monthly interim rates as reasonable and relieving Springs of its undertaking to make refunds, (7) relieving Springs of the requirement of filing a Status Report on or before March 5, 2008, and an Annual Report on or before April 30, 2008, and (8) requiring customer notice.

Based upon the foregoing, the Commission is of the opinion that the stipulation should be approved and the provisions of the stipulation should be incorporated into an order.

IT IS, THEREFORE, ORDERED as follows:

1. That the stipulation between the Public Staff and Springs is hereby approved.

2. That the Commission hereby accepts for filing the Agreement dated February 4, 2008, between Springs and Scotland County attached to the stipulation as an exhibit.

3. That Springs is hereby authorized to abandon the sewer utility system serving Springfield Village effective June 30, 2008, or the date the last customer ceases to use the system, whichever occurs first.

4. That the public hearing scheduled for March 27, 2008, in Laurinburg, North Carolina is hereby cancelled.

5. That a copy of this order shall be mailed with sufficient postage or hand delivered by Springs to all customers no later than 7 days after the date of this Order; and that Springs submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 15 days after the date of this Order.

6. That Springs shall provide written notification to the Commission when the last Springfield Village customer leaves the system.

7. That Springs is relieved of the previously-established obligation to file with the Commission a status report on March 5, 2008, and an Annual Report on or before April 30, 2008, and that the Public Staff and Springs are relieved of the obligation to prefile testimony.

8. That the previously approved $75.00 per month interim rate is approved as just and reasonable, and Springs is relieved of its undertaking to make refunds.

9. That, upon the earlier of written notification by Springs to the Commission that the last customer has left the system or June 30, 2008, both Docket Nos. W-650, Sub 3, and W-650, Sub 4, shall be considered closed, and the certificate of public convenience and necessity issued to Springs in Docket No. W-650, Sub 0, shall be cancelled.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of February, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

rb022508.06

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-650, Sub 3 and Sub 4, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of _________________ 2008.

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-650, Sub 3 and Sub 4.

Witness my hand and notarial seal, this the _____ day of _____________ 2008.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-354, SUB 236

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the matter of: Ocean Club Ventures, L.L.C., Complainant, v. Carolina Water Service, Inc. of North Carolina, Respondent	)))))))	ENFORCEMENT ORDER

HEARD ON: Tuesday, June 10, 2008, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners Lorinzo L. Joyner and James Y. Kerr, II

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Christopher J. Ayers, Hunton & Williams, Post Office Box 109, Raleigh, North Carolina 27602

For the Using and Consuming Public:

William E. Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On September 8, 2004, Carolina Water Service, Inc. of North Carolina (Carolina Water or CWS), the Public Staff of the North Carolina Utilities Commission (Public Staff), Monteray Shores, Inc. (MSI), and Buck Island, Inc. (BII), filed a Settlement Agreement that purported to resolve all of the issues that remained in dispute in this proceeding as of that date and requested the Commission to approve the Settlement Agreement.

According to the representations made by Carolina Water with the full knowledge of the other parties to this proceeding at the time the Settlement Agreement was submitted for Commission approval, the parties agreed that BII and MSI would convey their ownership interests in the backbone water and sewer facilities in Monteray Shores and Buck Island to Carolina Water; that BII and MSI would convey additional property through easement, license or otherwise in order to permit Carolina Water to modify, rehabilitate or expand the existing water and sewer facilities so as to provide sufficient capacity to meet the needs within the service area at full build-out; that Carolina Water would undertake the responsibility for financing and constructing any needed system upgrades; and that a plan had been developed that called for an upgrade and reconfiguration of the existing drain fields, the installation of an additional drain field within Monteray Shores, and the lowering of the groundwater table in proximity to the drain field so as to increase the capacity of the wastewater disposal system to disperse effluent. The proposed Settlement Agreement contemplated a more detailed utility facilities transfer agreement that would specify in greater detail the parcels and facilities to be conveyed.

On September 10, 2004, the Commission entered an Order Approving Settlement Agreement in which the Commission approved the Settlement Agreement, dismissed pending complaints asserted against BII and MSI by Carolina Water, dismissed a show cause proceeding that the Commission instituted against MSI, required Carolina Water to file monthly reports setting forth the status of efforts to implement the Settlement Agreement, required the filing of an application for approval to transfer the applicable land and facilities from BII and MSI to Carolina Water, and provided for the exercise of continuing Commission jurisdiction over the parties to this proceeding to the extent necessary to enforce the Settlement Agreement.

On December 20, 2005, Carolina Water filed a Petition for Approval of Asset Purchase Agreements in which it sought Commission approval of asset purchase agreements between Carolina Water and BII and Carolina Water and MSI, respectively.

On December 30, 2005, the Commission entered an Order Approving Purchase Agreements in which the Commission approved the Asset Purchase Agreements submitted by Carolina Water; required the parties to proceed in good faith to close on these agreements; ordered Carolina Water to take the steps necessary to expand the system in Monteray Shores as soon as possible; and ordered Carolina Water to continue filing monthly reports setting forth the status of the parties' efforts to close on the Asset Purchase Agreements and Carolina Water's efforts to obtain the necessary permits and to construct facilities needed to ensure expansion of the existing water production and wastewater treatment facilities.

On March 13, 2008, Carolina Water filed a Supplemental Report in which it stated that construction of a groundwater lowering pump station had been delayed "due to Bob DeGabrielle's unwillingness to sign over easement rights for discharge as previously agreed" to in the Asset Purchase Agreement.

On March 26, 2008, the Commission entered an Order to Show Cause in which the Commission ordered MSI to show cause on or before April 9, 2008, why it should not be subject to such penalties as the Commission deemed appropriate for violation of prior Commission orders. On April 7, 2008, Robert R. DeGabrielle, President of MSI, filed a response stating that MSI did not transfer certain asset rights sought by Carolina Water because Carolina Water was seeking easement rights in land that "was never included in the WWTP area for Monteray Shores/Buck Island and had never been discussed, requested or implied."

On May 30, 2008, the Commission entered an Order Scheduling Hearing to resolve the issues in dispute between the parties, including whether the easements sought by Carolina Water were provided for in the Asset Purchase Agreement between Carolina Water and MSI; the extent, if any, to which sanctions should be imposed on MSI in the event that the Commission concluded that MSI had failed to comply with prior Commission orders or other provisions of

North Carolina law; and, in the event that the easements sought by Carolina Water were not provided for in the Asset Purchase Agreement, whether MSI should still be required to convey the property rights in question to Carolina Water.

On June 6, 2008, in accordance with the provisions of the May 30, 2008, Order, Carolina Water prefiled the exhibits it intended to introduce at the hearing. MSI did not prefile any exhibits or other documentary evidence in accordance with the provisions of the May 30, 2008 Order. Additionally, despite proper notice to counsel, no one appeared on behalf of MSI at the scheduled hearing. Carolina Water was present at the hearing and offered the testimony of Mr. Carl Daniel and Mr. Robert Burgin. The Public Staff was present, but did not present any witnesses.

Based on the testimony presented at the hearing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. On September 8, 2004, Carolina Water, the Public Staff, MSI and BII entered into a Settlement Agreement to resolve all outstanding issues between the parties in this docket.

2. On September 10, 2004, the Commission approved the Settlement Agreement between the parties and stated that it "shall retain jurisdiction over the parties to this docket to oversee and enforce the implementation of the Settlement Agreement and to issue such additional orders as it deems necessary."

3. The Settlement Agreement designated specific ponds and green areas to which Carolina Water must be granted a perpetual right to utilize in connection with the expanded wastewater treatment facilities.

4. The Settlement Agreement identified Ponds 1 and 7 on Map C2 attached thereto as areas in Monteray Shores which Carolina Water must be granted a perpetual right to use.

5. The Settlement Agreement identified green space in the wetlands adjoining the wastewater treatment plant as an area in which Carolina Water must be granted a perpetual right to spray irrigate.

6. Carolina Water and MSI entered into an Asset Purchase Agreement dated December 20, 2005, whereby certain property rights were to be conveyed by MSI to Carolina Water for the construction and operation of expanded wastewater treatment facilities.

7. In the Asset Purchase Agreement, MSI agreed to convey to Carolina Water, in fee simple, the property on which the wastewater treatment and water treatment facilities were located along with well sites.

8. In the Asset Purchase Agreement, MSI agreed to convey to Carolina Water "a valid easement or license" to allow Carolina Water to utilize specifically identified ponds and green space in connection with the operation of the expanded wastewater treatment facility.

9. The Asset Purchase Agreement identified Ponds 1 and 7 in Exhibit C-1, page 4 of 4, as areas in Monteray Shores which Carolina Water must be granted a perpetual right to use.

10. The Asset Purchase Agreement identified green space in the wetlands adjoining the wastewater treatment plant in Exhibit C-1, page 4 of 4, as an area in which Carolina Water must be granted a perpetual right to spray irrigate.

11. The Asset Purchase Agreement identified green space surrounding commercial property in Monteray Shores in Exhibit C-1, page 3 of 4, as an area in which Carolina Water must be granted a perpetual right to spray irrigate.

12. On December 30, 2005, the Commission approved the Asset Purchase Agreement between Carolina Water and MSI and ordered the parties to proceed in good faith to close on the agreement.

13. On October 3, 2006, Carolina Water caused to be filed with the Currituck County Register of Deeds a set of easement maps detailing the green space and ponds for which perpetual easement and spray irrigation rights must be conveyed by MSI to Carolina Water. The easement maps included pages 3 of 4 and 4 of 4 of Exhibit C-1 to the Asset Purchase Agreement.

14. On October 3, 2006, Carolina Water's attorney, Mr. Ed Finley, forwarded a set of closing documents to MSI's attorney, Mr. John O'Connor, which included an Effluent Easement and Spray Irrigation Agreement that conveyed easement and spray irrigation rights to the ponds and green space identified in the Asset Purchase Agreement.

15. Mr. O'Connor returned a revised version of the Effluent Easement and Irrigation Agreement via an e-mail to Mr. Finley on November 30, 2006.

16. On January 10, 2007, Mr. Finley transmitted a set of revised closing documents to BII's attorney, Mr. Tom Nash, with regard to the asset purchase agreement between Carolina Water and BII. The revised set of closing documents contained revisions to the Effluent Easement and Irrigation Agreement that were made at the request of MSI.

17. On January 25, 2007, Mr. Finley forwarded Mr. O'Connor a new set of closing documents under the Asset Purchase Agreement.

18. On February 3, 2007, Mr. O'Connor stated in an e-mail to Carolina Water's attorney, Mr. Christopher Ayers, that he would review the Effluent Easement and Irrigation Agreement and get back with Mr. Ayers concerning any issues.

19. On March 21, 2007, the North Carolina Department of Environment and Natural Resources (DENR) - Division of Water Quality issued Permit No. WQ 0009772 (Permit) authorizing the construction of the expansion of the wastewater treatment facility.

20. On June 29, 2007, BII executed the Effluent Easement and Irrigation Agreement.

21. On September 11, 2007, following approval by Currituck County, Carolina Water caused to be filed amended final plats for the Monteray Shores PUD WWTP that carved out the wastewater treatment parcel to be conveyed by MSI to Carolina Water.

22. On October 10, 2007, Mr. Ayers transmitted to Mr. DeGabrielle revised closing documents for the Asset Purchase Agreement, including the Effluent Easement and Irrigation Agreement.

23. Mr. DeGabrielle, on behalf of MSI, executed the closing documents with the exception of the Effluent Easement and Irrigation Agreement.

24. Carolina Water and MSI agreed to close on all outstanding issues under the Asset Purchase Agreement so that construction could commence on the wastewater treatment plant expansion as soon as possible.

25. MSI agreed to resolve the issues related to the Effluent Easement and Irrigation Agreement quickly so that the transaction could be completed.

26. On October 18, 2007, Carolina Water recorded the deed conveying the wastewater treatment plant area and related access easements with the Currituck County Register of Deeds.

27. On October 19, 2007, Mr. Ayers e-mailed Mr. O'Connor in an effort to resolve the issues related to the Effluent Easement and Irrigation Agreement and requested a redline with proposed revisions. MSI did not provide Carolina Water with proposed revisions.

28. Carolina Water notified the Commission of the partial closing and the unexecuted Effluent Easement and Irrigation Agreement in its monthly report filed in this docket on October 22, 2007.

29. Carolina Water, through its attorney, continued to request execution of the Effluent Easement and Irrigation Agreement through phone conversations and e-mail correspondence, but received no revisions from MSI.

30. On November 14, 2007, Mr. Ayers e-mailed Mr. O'Connor for the purpose of requesting MSI's proposed revisions to the Effluent Easement and Irrigation Agreement. Mr. O'Connor responded on November 16, 2007 that he would get to the issue.

31. Carolina Water informed the Commission in monthly reports filed on November 21, 2007, December 20, 2007, January 18, 2008, and February 13, 2008, that the parties were working to resolve issues regarding the Effluent Easement and Irrigation Agreement.

32. In a letter dated January 18, 2008, Mr. Daniel Khoury, attorney for Mr. DeGabrielle, requested that Carolina Water reimburse MSI in the amount of $4,319.58 for 2007 property taxes on the wastewater treatment parcel.

33. On January 24, 2008, Mr. Ayers e-mailed Mr. O'Connor and informed him that construction had commenced on the wastewater treatment facility expansion and requested proposed revisions and execution of the Effluent Easement and Irrigation Agreement.

34. In a letter dated January 31, 2008, Carolina Water responded to Mr. Khoury's letter and stated that it was willing to discuss the matter but that the parties must first resolve the outstanding issues related to the Effluent Easement and Irrigation Agreement. Carolina Water attached a draft of the Effluent Easement and Irrigation Agreement to its response.

35. In an e-mail message dated February 5, 2008, Mr. DeGabrielle denied his obligation to grant easements rights and offered to sell the property to Carolina Water "once these taxes are paid and a mutually agreeable price and contract have been entered into." Mr. DeGabrielle instructed Carolina Water to direct all future correspondence on the matter to him.

36. Mr. DeGabrielle's e-mail dated February 5, 2008 marked the first time that MSI disputed Carolina Water's rights to the ponds and green space in Monteray Shores.

37. On February 12, 2008, Mr. DeGabrielle again demanded reimbursement for certain property taxes before having any further discussions regarding the Effluent Easement and Irrigation Agreement.

38. Carolina Water subsequently rendered payment to Mr. DeGabrielle for the disputed property taxes in an effort to resolve the Effluent Easement and Irrigation Agreement.

39. In its monthly report dated March 13, 2008, Carolina Water stated that construction of the ground water lowering pump station discharge line had been delayed due to Mr. DeGabrielle's unwillingness to sign over easements to the ponds as provided in the Asset Purchase Agreement.

40. On April 28, 2008, Mr. DeGabrielle requested from Carolina Water an original set of plans submitted by Carolina Water to the DENR and Currituck County for approval of the expanded wastewater treatment facility. Mr. DeGabrielle stated that he would review the plans and contact Carolina Water on how to resolve the easement issue.

41. In a letter dated May 15, 2008, Carolina Water forwarded the wastewater treatment plans to Mr. DeGabrielle per his request along with applicable portions of the Asset Purchase Agreement.

42. Mr. DeGabrielle has not corresponded with Carolina Water or its attorney following his receipt of the wastewater treatment plans that were mailed by Carolina Water on May 15, 2008.

43. Mr. DeGabrielle has refused to allow Carolina Water to access Pond 1 for the installation of groundwater lowering equipment that is necessary for the operation of the wastewater treatment plant under the Permit.

44. Mr. DeGabrielle notified Carolina Water's engineer and contractor on site in Monteray Shores that no work could be performed on MSI property until the issue has been resolved.

45. MSI has posted "no trespassing" signs on the property and notified the Currituck County magistrate of the issue.

46. Carolina Water has been unable to gain access to Pond 1 or the utility area approaching Pond 1 due to the arrest threats made by Mr. DeGabrielle.

47. The Access and Utility Area Easement Agreement executed by MSI in favor of Carolina Water and dated October 11, 2007, grants Carolina Water easement access to the utility area approaching Pond 1.

48. Carolina Water's contractor has completed its work and is no longer on site, so that Carolina Water will incur considerable expense for remobilization once access easement rights are obtained.

49. Carolina Water's hydrogeologist is unable to test the groundwater lowering drains because there is no place to discharge the test water.

50. Carolina Water must complete construction related to Pond 1 by the end of October 2008 in order to meet its May 2009 timeframe for completing the expansion project.

51. The Effluent Easement and Irrigation Agreement will grant Carolina Water the easement and spray irrigation rights to Ponds 1 and 7 and the green space required in the Asset Purchase Agreement.

52. MSI has provided no revisions to the draft Effluent Easement and Irrigation Agreement or suggested any resolution of the current dispute since receiving a draft of the Effluent Easement and Irrigation Agreement in October 2007.

53. Carolina Water cannot operate the expanded wastewater treatment facility in accordance with its Permit without utilizing Ponds 1 and 7 and the green space as called for in the Effluent Easement and Irrigation Agreement.

54. Carolina Water must have easement access to Pond 1 in order to store groundwater that is pumped from the northeast side of the wastewater treatment plant. The infiltration basins will not function properly without the lowering of the groundwater.

55. Carolina Water must have easement rights in Pond 7 for use as a reserve pond.

56. Pursuant to DENR regulations, Carolina Water must set aside 2,500 square feet of useable spray area per 1,000 gallons of permitted wastewater capacity either as green space or reserve area.

57. Further delay in granting Carolina Water the necessary easement and spray irrigation rights will delay construction of the facility and hinder the targeted in-service operation date of May 2009.

58. MSI has breached the terms of the Settlement Agreement and Asset Purchase Agreement and has violated the Commission's orders dated September 10, 2004, and December 30, 2005, respectively, approving those agreements.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

Based on the evidence contained in the record, the Commission finds and concludes that MSI has breached the terms of the Settlement Agreement and Asset Purchase Agreement and has violated the Commission's orders dated September 10, 2004, and December 30, 2005, respectively, approving those agreements.

Under "Obligations of MSI and BII," paragraph 3 of the Settlement Agreement, MSI agreed to

> convey to CWS through grant of easement or license, sufficient property rights to permit CWS to install, maintain, inspect, operate and repair sufficient additional drain field facilities, facilities to lower the water table and effluent reuse disposal facilities in designated open, green or utility space and on other common or reserved areas to permit CWS to lower the water table and to transport the effluent from the wastewater treatment facilities to the locations where additional drain field disposal or spray irrigation can occur.

Additionally, paragraph 4 requires MSI to convey proposed designated green areas within Monteray Shores as shown in map C2 attached to the Settlement Agreement. Paragraph 5 further requires MSI to grant licenses or easements to CWS "for the use of existing ponds within the service area," including the ponds designated "1" and "7" on Settlement Agreement map C2. In paragraph 17, MSI agreed to "not take any steps to undermine the agreement reached by the parties." Finally, MSI agreed to use good faith efforts to negotiate and execute any documents necessary to fulfill the terms of the Settlement Agreement.

The Asset Purchase Agreement entered into between Carolina Water and MSI specifically spelled out the easements to green space and ponds that needed to be granted to permit the construction and operation of the expanded wastewater treatment plant in accordance with the Permit. Paragraph 1.1(B) provided:

> Upon the terms and subject to the conditions of this Agreement, at the Closing, Seller shall sell, convey, transfer, assign and deliver to Purchaser a valid easement or license with respect to Property shown on the attached Exhibit C related to the operation of the Facilities, and Purchaser hereby agrees to acquire or purchase the same from Seller.

Section 1.3(B) provides that, at Closing, MSI will convey an "easement or license for all property interests owned by [MSI] as shown on the attached Exhibit C." Exhibit C specified:

All property designated as:

a. Proposed designated green area to which perpetual right to spray irrigate must be granted to Carolina Water Service Inc. of North Carolina;

b. Property designated ponds to which perpetual right to place treated wastewater spray irrigation and disposal by pond leakage must be granted to Carolina Water Service Inc. of North Carolina;

c. Existing designated green area to which perpetual right to spray irrigate must be granted to Carolina Water Service Inc. of North Carolina;

on sheets 3 of 4 and 4 of 4 of Easement Map for Carolina Water Service Inc. of North Carolina prepared by Stroud Engineering P.A. dated February 17, 2005 attached as Exhibit C-1.

Exhibit C-1, page 4 of 4, clearly identifies Pond 1 and Pond 7 as property to which perpetual easement or license rights must be conveyed to Carolina Water. Exhibit C-1, page 4 of 4, also clearly identifies the green area to which the perpetual right to spray irrigate must be granted to Carolina Water. Exhibit C-1, page 3 of 4, clearly identifies additional green space within Monteray Shores where the perpetual right to spray irrigate must be granted to Carolina Water. The language of both the Settlement Agreement and Asset Purchase Agreement is clear and unambiguous and does not require interpretation. The language of both agreements requires MSI to convey property access rights to Carolina Water with respect to Ponds 1 and 7 and the green areas found on Asset Purchase Agreement Exhibit C-1, pages 3 of 4 and 4 of 4.

The drafts of the Effluent Easement and Irrigation Agreement submitted into evidence by Carolina Water effectuate the easement grants contemplated in the Settlement Agreement and Asset Purchase Agreement. Sections 1.7 and 1.8 of the Effluent Easement and Irrigation Agreement specify the easement areas to be conveyed by MSI to Carolina Water. The easement maps listed in Section 1.8 are the same easement maps that comprise Asset Purchase Agreement Exhibit C-1, pages 3 of 4 and 4 of 4. No new additional property or easement rights are sought through the Effluent Easement and Irrigation Agreement other than those previously detailed in the Asset Purchase Agreement and recorded with the Currituck County Register of Deeds. The Effluent Easement and Irrigation Agreement merely effectuates the outstanding obligations of the Asset Purchase Agreement. The Commission has received no evidence tending to show that the easement and irrigation rights specified in the Effluent Easement and Irrigation Agreement materially differ from those set out in the Settlement Agreement and Asset Purchase Agreement. Accordingly, the Commission sees no valid reason why MSI should not be required to execute the Effluent Easement and Irrigation Agreement and fulfill its obligations thereunder.

Carolina Water offered testimony at the hearing regarding the necessity of the ponds and green space to the operation of the expanded wastewater treatment plant through its engineer, Mr. Robert Burgin. Mr. Burgin testified that the expanded wastewater treatment plant cannot be fully operated without Pond 1. Carolina Water must have easement access to Pond 1 in order to store groundwater that is pumped from the northeast side of the plant and flows underneath the infiltration basins. Without the lowering of the groundwater, the infiltration basins will not function properly and the plant cannot be operated in compliance with its Permit. Additionally, failure to properly lower the groundwater as required in the Permit can result in ponding, which would violate the Permit. MSI failed to install a needed groundwater lowering device when it originally constructed the system, thereby causing the spray irrigation system to operate in a less than optimal manner. Carolina Water must be allowed to install the necessary equipment in order to properly operate the plant and comply with its Permit. Pursuant to the Permit, Carolina Water also must have easement rights in Pond 7 for use as a reserve pond to accept groundwater or to serve as an infiltration basin.

Carolina Water also must have easement and spray irrigation rights to the green space specified in the Asset Purchase Agreement and Effluent Easement and Irrigation Agreement. DENR regulations require that coastal area wastewater facilities set aside 2,500 square feet of useable spray area per 1,000 gallons of permitted wastewater capacity as either green space or reserve area. Such area is held in reserve in the event that the primary wastewater disposal system should fail and additional space is required for the disposal of treated effluent. Carolina Water must have access and spray rights to the green space as a reserve area in the event the high-rate infiltration system fails to work properly. Without the green space covered by the Effluent Easement and Irrigation Agreement, the expanded wastewater treatment plant cannot be operated in compliance with its Permit.

As of the date of the hearing, Carolina Water has been unable to complete the construction of the groundwater lowering system because MSI has denied it access to the area immediately adjacent to Pond 1 and the pond itself. MSI has denied Carolina Water access to the area approaching Pond 1 despite the fact that MSI executed an easement granting Carolina Water access rights to the utility area approaching Pond 1. In this same deed of easement, the Effluent Easement and Irrigation Agreement is specifically referenced. MSI's behavior completely conflicts with actions it has already taken in partially closing on the Asset Purchase Agreement.

MSI's obstruction has already cost Carolina Water both time and expense in expanding the plant. As the contractor has left the site, Carolina Water will be required to expend additional sums of money to remobilize the contractor to complete the work related to Pond 1. Additionally, Carolina Water's hydrogeologist has been unable to complete testing of the groundwater drainage basins. In the event Carolina Water is unable to complete work related to Pond 1 by October 2008, the wastewater treatment plant expansion will likely miss its May 2009 completion goal and have to extend the construction process into the peak 2009 tourist season and beyond.

While the Commission has not thoroughly investigated MSI's compliance with other aspects of the Asset Purchase Agreement in the context of an evidentiary proceeding, it appears that MSI has conveyed property rights as required by the Asset Purchase Agreement with the exception of the property rights covered by the Effluent Easement and Irrigation Agreement. MSI has conveyed the fee parcel to the wastewater and water treatment facilities and access easements related to each. MSI has conveyed the personal property and fixtures comprising both facilities. MSI also conveyed the Highway 12 well fields via quitclaim deed to Carolina Water. The Commission notes that it took almost two years for MSI to convey the property it agreed to convey in December 2005. MSI has had ample time to resolve issues with regard to the Effluent Easement and Irrigation Agreement, and there is no valid explanation for why MSI has refused to meet its remaining obligation with regard to the easement rights to the ponds and green space in that time period.

Carolina Water presented testimony through its witness, Mr. Carl Daniel, regarding the efforts made by the company and its attorneys to secure the execution of the Effluent Easement and Irrigation Agreement by MSI and BII. Mr. Daniel testified that Carolina Water, through its attorneys, has made repeated efforts to secure the execution of the Effluent Easement and Irrigation Agreement and to identify and resolve MSI's unspecified issues with the agreement when they arose late in the process. MSI was first presented with the Effluent Easement and Irrigation Agreement on October 3, 2006. Since that date, over twenty months have passed without a resolution. While MSI presented revisions to the drafting documents to Carolina Water's attorney in late 2006, the record contains no evidence that any critical issues existed that would have caused MSI to subsequently refuse to execute the document. MSI provided revisions to Carolina Water in November 2006, but did not object to the grant of property rights to the ponds or green space at that time. In February 2007, MSI's attorney stated that he would review the Effluent Easement and Irrigation Agreement and raise any issues. Again, MSI raised no objections. BII signed the three-party agreement on June 29, 2007. MSI has been notified of this fact.

Carolina Water and MSI engaged in discussions that included the ponds and green space at issue in this proceeding as early as September 2004. Additionally, Carolina Water consulted with MSI on the plant design during the Permit process. MSI cannot now claim that the Effluent Easement and Irrigation Agreement is a new agreement or that Carolina Water seeks property rights that were not previously agreed to or contemplated by the parties. MSI's assertion that the ponds and green space "was never included in the WWTP area for Monteray Shores/Buck Island and had never been discussed, requested or implied" is simply false. MSI was aware of the agreement and MSI's obligation to convey the rights contained therein.

MSI gave no reason to believe that it would not execute the Effluent Easement and Irrigation Agreement prior to the closing on the other documents in October 2007. MSI had numerous opportunities to raise objections or present additional revisions to the terms of the Effluent Easement and Irrigation Agreement but failed to do so. At the time of execution of the other closing documents in October 2007, MSI gave Carolina Water no reason to believe that it would refuse to execute the Effluent Easement and Irrigation Agreement. Mr. Daniel testified that Carolina Water only became aware that MSI disputed the utility's rights to the ponds and green space in Mr. DeGabrielle's e-mail to Mr. Ayers on February 5, 2008. MSI has failed to provide specific objections or suggested revisions to the Effluent Easement and Irrigation Agreement since October 2007.

Mr. Daniel testified that Carolina Water closed on all other deeds and documents related to the Asset Purchase Agreement in order to move forward as quickly as possible with expansion of the wastewater treatment plant. Carolina Water closed on the other documents and initiated construction on the expansion on the basis of a good faith understanding that the Effluent Easement and Irrigation Agreement would be resolved quickly by the parties. Carolina Water's capital investment in the expansion to date is approximately $5 million. Mr. Daniel testified that Carolina Water would not have made the investment and moved forward with the expansion of the wastewater treatment facility had it known MSI would dispute Carolina Water's rights to the ponds and green space. Carolina Water has further reason for concern based on the interest the Department of Transportation has shown in potentially selecting the site that includes Pond 1 for location of a new bridge across the sound. In the event MSI were to convey the property without prior assignment of the necessary easement rights, Carolina Water would be required to redesign the plant expansion, resulting in significant delays and expense.

MSI's failure to timely work with Carolina Water to identify and resolve any issues with the Effluent Easement and Irrigation Agreement demonstrates a lack of good faith on the part of MSI in fulfilling its obligations under the Settlement Agreement and Asset Purchase Agreement. MSI failed to act expediently to identify issues related to the ponds and green space, if any in fact existed, and failed to formulate alternative solutions. MSI failed to cooperate with Carolina Water in achieving the objective of the Settlement Agreement and in honoring its obligation to not take any action that would undermine the agreement of the parties. MSI has failed to honor its obligations under Sections 1.1(B) and 1.3(B) of the Asset Purchase Agreement. MSI has further failed to use commercially reasonable efforts to make effective the transactions of the Asset Purchase Agreement as provided in Section 2.11 of that agreement.

The record assembled in this case is devoid of any evidence justifying MSI's failure to execute the Effluent Easement and Irrigation Agreement. Despite proper notice, MSI failed to appear at the show cause hearing on June 10, 2008, and present evidence in its defense. Carolina Water has demonstrated through its witnesses and exhibits that it is entitled to easement rights to Ponds 1 and 7 and the green space pursuant to the Settlement Agreement and Asset Purchase Agreement - Exhibit C-1, pages 3 of 4 and 4 of 4. Carolina Water has further demonstrated that such easement rights are necessary to operate the expanded wastewater treatment plant in compliance with its Permit. Having failed to demonstrate to the Commission any deficiencies in the Effluent Easement and Irrigation Agreement as finally proposed by Carolina Water, the Commission concludes that MSI should be required to immediately execute the Effluent Easement and Irrigation Agreement in the same form as that document was executed by BII on June 29, 2007. The Commission further concludes that MSI should immediately cease and desist from denying Carolina Water access to the subject property and obstructing construction of the plant expansion. Further delays or obstruction on the part of MSI are unacceptable.

MSI's eleventh hour attempt to dispute Carolina Water's easement rights to Ponds 1 and 7 and green space in Monteray Shores also demonstrates a fundamental disregard for this Commission's orders in this docket. The Commission approved both the Settlement Agreement and Asset Purchase Agreement between MSI and Carolina Water, thereby giving each agreement the effect of a Commission order. MSI has presented no good faith explanation for its failure to comply with the Commission's orders. The Commission finds MSI's behavior to be willful and sanctionable.

As discussed above, MSI partially closed on the Asset Purchase Agreement on October 18, 2007, when the deeds to the wastewater and water treatment parcel were executed and delivered and were recorded with the Currituck County Register of Deeds. Based on the evidence of MSI's subsequent behavior with regard to resolving the outstanding easement rights to the ponds and green space, it appears to the Commission that MSI had no intention of closing on the remainder of the deal. The record contains numerous e-mail exchanges between the parties, and Mr. Daniel testified to phone conversations regarding the Effluent Easement and Irrigation Agreement. These communications culminated in an outright denial of Carolina Water's rights to obtain easements permitting the use of certain MSI property in connection with the construction and operation of the expanded facilities by MSI in disregard of the prior agreements between the parties and Commission orders. Accordingly, the Commission orders MSI to execute the Effluent Easement and Irrigation Agreement in the form executed by BII on June 29, 2007, within thirty (30) days of the date of this Order. MSI shall pay to the Commission a penalty in the amount of $1,000 per day, pursuant to G.S. 62-310(a), beginning thirty (30) days from the date of this Order and continuing daily until MSI executes the Effluent Easement and Irrigation Agreement and ceases to impair Carolina Water's expansion and operation of the wastewater treatment plant. In the event that MSI executes the Effluent Easement and Irrigation Agreement within thirty (30) days from the date of this Order and does not further impair Carolina Water's efforts to expand and operate the wastewater treatment plant, no monetary penalty will be due. If MSI fails to voluntarily execute the Effluent Easement and Irrigation Agreement and/or pay any penalty in a timely manner, the Commission Staff is hereby directed to seek enforcement of this Order and recovery of said penalty in an action instituted in the Superior Court of Wake County pursuant to G.S. 62-310.

IT IS THEREFORE ORDERED AS FOLLOWS:

1. That MSI shall execute the Effluent Easement and Irrigation Agreement in the form executed by BII on June 29, 2007, within thirty (30) days of the date of this Order in order to comply with its obligations to convey easement rights to Ponds 1 and 7, green space and spray area as denoted and required by the Settlement Agreement and Asset Purchase Agreement to Carolina Water.

2. That MSI shall cooperate with Carolina Water in executing and/or recording any additional documentation necessary to effectuate the conveyance of the easement rights ordered herein in a timely manner.

3. That MSI shall cooperate with Carolina Water in negotiating and executing any further agreements necessary to implement the Settlement Agreement and Asset Purchase Agreement in a timely manner.

4. That MSI is ordered to pay to the Commission a penalty in the amount of $1,000 per day, pursuant to G.S. 62-310(a), beginning thirty (30) days from the date of this Order and continuing daily until MSI executes the Effluent Easement and Irrigation Agreement, ceases to impair Carolina Water's expansion and operation of the wastewater treatment plant, and takes all other steps reasonably necessary to complete the process of constructing and operating the expanded wastewater treatment plant. In the event that MSI executes the Effluent Easement and Irrigation Agreement within thirty (30) days from the date of this Order and does not further impair Carolina Water's efforts to expand and operate the wastewater treatment plant, no monetary payment is required. If MSI fails to voluntarily pay the penalty and/or take any other action required by this order in a timely fashion, the Commission Staff is hereby directed to seek

enforcement of this Order and recovery of said penalty in an action instituted in the Superior Court of Wake County pursuant to G.S. 62-310.

5. That MSI is hereby again ordered to not interfere with CWS's operation, construction or ownership of the system and will be subject to additional penalties in the event that any such interference occurs.

6. That the Commission shall continue to exercise jurisdiction over the parties to this proceeding to the extent necessary to enforce the Settlement Agreement, Asset Purchase Agreement and this Order.

7. That a copy of this Order shall be served upon MSI in addition to being served upon counsel for MSI.

ISSUED BY ORDER OF THE COMMISSION:
This the 15th day of July, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc071508.02

DOCKET NO. W-1236, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Enviracon Utilities, Inc. Post Office Box 610, Tarboro, North Carolina 27886, for Authority to Make Emergency Special Assessment to Ratepayers and/or Application for Authority to Discontinue Sewer Utility Service to Island Beach and Racquet Club and The Sheraton Atlantic Beach Oceanfront Hotel, in Carteret County, North Carolina	)))))))	ORDER APPROVING EXPENDITURES AND REQUIRING REIMBURSEMENT

BY THE COMMISSION: On January 31, 2008, GR&S Atlantic Beach, LLC (GR&S) filed a letter informing the Commission that it waived reimbursement for an invoice from Gannett Fleming Engineers in the amount of $14,838.06 for conducting a feasibility study and a GR&S invoice seeking to pass through a fifteen percent (15%) charge by Trinity Hotel Investors, LLC (Trinity) for overhead associated with Trinity having provided all the resources for the planning, procurement, engineering, approvals, access, implementation and financing of the replacement of a treatment tank used by Enviracon Utilities, Inc. (Enviracon). Additionally, GR&S requested that the Public Staff seek a Commission order requiring Island Beach and Racquet Club Condominium Owners Association, Inc. (IBRC) to reimburse GR&S forty percent (40%) of the undisputed engineering and construction costs, expenses, legal fees and finance charges associated with the tank replacement effort, with such finance charges calculated in accordance with the Commission's Orders, up through the date of reimbursement.

Neither the Public Staff nor IBRC filed a formal response to GR&S' letter.

On February 29, 2008, the Commission issued an Order Requiring the Public Staff and IBRC to respond to the January 31, 2008 letter and to address any other outstanding issues regarding the reimbursement of expenditures made to replace the treatment tank by March 14, 2008.

On March 14, 2008, the Public Staff submitted comments concerning the January 31, 2008 GR&S letter; the expenditures made by GR&S relating to the wastewater treatment system; and the status of the Commission-controlled, Public Staff supervised, Enviracon Capital Escrow Account (Capital Escrow Account) in a filing denominated as the Public Staff Audit Report on Failed Wastewater Treatment Plant Expenditures (Public Staff Audit Report). The Public Staff Audit Report concurred with GR&S' withdrawal of its claims for reimbursement of the 15% charge for overhead associated with Trinity's provision of resources and financing relating to the tank replacement effort and reimbursement for expenditures made to secure the Gannett Fleming feasibility study due to the lack of supporting documentation. In addition, the Public Staff Audit Report recommended Commission approval of total engineering fees and expenses of $576,634, legal fees of $9,126 and finance charges of $75,351 (the finance charges included interest through February 29, 2008.). The Public Staff recommended that IBRC be ordered to pay $94,285 to the Capital Escrow Account, and $170,159 plus the additional finance charges to GR&S, within ten days of the Commission's order as contemplated by the Commission's orders of November 18, 2006 and January 26, 2007 respectively.

The Public Staff also provided a detailed examination of the Capital Escrow Account. The Public Staff stated that on December 6, 2006, IBRC paid $50,000 into the Capital Escrow Account as ordered by the Commission. The Public Staff thereafter itemized the payments made from the Capital Escrow Account and concluded that the current balance in the Capital Escrow Account is $1,042 ($50,000 less $48,958).

It is the Public Staff's understanding that DENR will soon approve Enviracon's plans and specifications for the capital improvements necessary to bring the wastewater utility system into compliance with DENR's requirements, so that the actual construction process can begin. The first step in the construction process will be the ordering of plant equipment. Therefore, the Public Staff concluded that the Capital Escrow Account would need significant additional funding as soon as possible.

Finally, the Public Staff commented on Enviracon's Summary Report on the Status of Capital Upgrades filed on January 22, 2008, which consisted of a January 17, 2008 Summary Status Report (Delta Report) by Delta Consultants (Delta). In the Delta Report, DENR approval of the upgrades was anticipated by February 19, 2008, with plant equipment to be ordered shortly thereafter. However, DENR was continuing to review the plans and specifications on February 25, 2008, and, as of the filing of the Public Staff's comments on March 14, 2008, approval from DENR had not been received. DENR approval has apparently been delayed by at least one month.

According to the Public Staff, the Delta Report section entitled Current Estimate of Capital Cost Requirements and Milestones for Need of Funds stated that a total of $164,000 would be needed through late March 2008. However, with the delay in DENR, the need for payments in that amount to be made from the Capital Escrow Account had been delayed to at least the end of April 2008. The Public Staff recommended that the Commission order GR&S to pay $100,000 into the Capital Escrow Account on or before April 30, 2008, so there would be adequate funds in the Capital Escrow Account, resulting from that payment, taking the $94,285 payment by IBRC into account.

On March 14, 2008, IBRC made a filing stating no exceptions to the recommendations advanced by the Public Staff.

After fully considering the recent filings of the parties and the record proper, the Commission concludes:

1. That GR&S has withdrawn its requests relating to reimbursement relating to an invoice from Gannett Fleming Engineers in the amount of $14,838.06 for conducting a feasibility study and a GR&S invoice seeking to pass through a fifteen (15%) charge by Trinity for overhead associated with Trinity having provided all the resources for the planning, procurement, engineering, approvals, access, implementation and financing of the tank replacement effort;

2. That the Commission should honor GR&S' decision in that regard;

3. That the Public Staff recommended Commission approval of GR&S expenditures for total engineering fees and expenses of $576,634, legal fees in the amount of $9,126 and finance charges of $75,351, inclusive of finance charges through February 29, 2008;

4. That the expenditures made by GR&S for said fees and expenses were reasonable and prudent;

5. That a detailed examination of the Capital Escrow Account indicated that, on December 6, 2006, IBRC paid $50,000 into the Capital Escrow Account as ordered by the Commission;

6. That itemized payments made from the Capital Escrow Account to date total $48,958; and that the current balance in the Capital Escrow Account is $1,042;

7. That the expenditures from the Capital Escrow Account to date were reasonable and prudent;

8. That DENR will soon approve Enviracon's plans and specifications for the capital improvements necessary to bring the wastewater utility system into compliance with DENR's requirements, so that actual construction can then begin, with the first step being the ordering of plant equipment;

9. That the Capital Escrow Account will need significant additional funding as soon as possible to facilitate the construction of the needed capital improvements;

10. That, in accordance with prior Commission orders, IBRC's forty percent (40%) share of the expenditures (inclusive of finance charges as of February 29, 2008) totals $264,444;

11. That the Public Staff recommended that IBRC be ordered to pay $94,285 to the Capital Escrow Account and $170,159, plus the additional finance charges, to GR&S, within ten days of the Commission's order;

12. That IBRC did not object to the Public Staff's recommendation;

13. That IBRC should be ordered to pay $94,285 to the Capital Escrow Account, and $170,159 (plus the additional finance charges) to GR&S, within ten days of the Commission's order;

14. That Enviracon's Summary Report on the Status of Capital Upgrades filed on January 22, 2008, which consisted of the January 17, 2008 Delta Report, indicated that DENR approval of the upgrades was anticipated by February 19, 2008, with plant equipment to be ordered soon thereafter, resulting in the necessity to make the required down payments;

15. That DENR was continuing to review the plans and specifications on February 25, 2008 and, as of the date of the filing of the Public Staff's comments on March 14, 2008, approval from DENR had not been received;

16. That DENR approval apparently has been delayed at least one month;

17. That, according to the Public Staff, the Delta Report section entitled Current Estimate of Capital Cost Requirements and Milestones for Need of Funds indicated that a total of $164,000 would be needed through late March 2008;

18. That, with the delay in DENR approval, the need for payment from the Capital Escrow Account has been delayed until at least the end of April 2008;

19. That the Current Estimate of Capital Cost Requirements and Milestones for Need of Funds stated that a total of $164,000 would be needed through late April 2008;

20. That this estimate of anticipated costs is reasonable;

21. That the Public Staff recommended that the Commission order GR&S to pay $100,000 into the Capital Escrow Account on or before April 30, 2008, so that there will be adequate funds in the Capital Escrow Account, taking the $94,285 payment by IBRC into account;

22. That GR&S did not object to the recommendation; and,

23. That GR&S shall pay $100,000 or more into the Capital Escrow Account on or before April 30, 2008, so that there will be adequate funds in the Capital Escrow Account, taking the $94,285 payment by IBRC into account.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of April, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Lh041008.01

DOCKET NO. W-176, SUB 32
DOCKET NO. W-176, SUB 29

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-176, SUB 32

In the Matter of Application of Scientific Water and Sewerage Corporation, 112 Scientific Lane, Jacksonville, North Carolina 28540 for Authority to Increase Rates for Water and Sewer Utility Service in All Its Service Areas in Onslow County, North Carolina DOCKET NO. W-176, SUB 29 In the Matter of Notification of Intention to Begin Operations in Area Contiguous to Present Service Area in Maynard Manor Subdivision in Onslow County, North Carolina	ORDER RECOGNIZING CONTIGUOUS EXTENSION, APPROVING RATES, ACCEPTING BOND, REQUIRING CONFERENCE, AND CLOSING DOCKET

BY THE COMMISSION: On February 10, 2006, the Commission issued a Recommended Order in the above-captioned dockets granting partial rate increase; closing Docket No. W-176, Sub 30; requiring bond; and requiring further action by Scientific Water and Sewerage Corporation (Scientific or Company) with respect to certain items as set forth in the decretal paragraphs of said Order. On April 17, 2006, the Commission issued an Order Overruling Exceptions and Affirming Recommended Order. On April 18, 2006, the Commission issued an Order Approving Final Rates and Requiring Notice in the above-captioned dockets.

Decretal Paragraph No. 4 of the February 10, 2006 Order required that Scientific file, within 60 days of the issuance date of said Order, a report addressing the specific steps to be taken regarding certain improvements to its water and sewer systems including the detailed cost information and estimated timeframe for completion of each step. Decretal Paragraph No. 5 of said Order required that Scientific file, within six months of the Order's issuance date, a progress report showing the status of said improvements, including funding obtained and the timeframe for completion. Further, Decretal Paragraph No. 6 of said Order required that Scientific post a bond in the amount of $130,000 in connection with the contiguous extension of sewer service in Maynard Manor Subdivision.

On December 29, 2006, Scientific filed its first report.

On January 3, 2007, Scientific filed an amended report which included the appendices which were inadvertently excluded from its December 29, 2006 Report.

On February 8, 2007, the Public Staff filed its response to Scientific's report.

On August 6, 2007, the Commission issued an Order Requiring Reports. Decretal Paragraph No. 3 of said Order required that the Public Staff discuss with Scientific, on or before September 6, 2007, any other viable alternatives relating to the $130,000 bonding requirement for the contiguous extension of sewer service in Maynard Manor Subdivision that might be available to the Company in addition to the two proposals suggested by Scientific in its January 3, 2007 Report. Further, Decretal Paragraph No. 4 of said Order required that the Public Staff file, on or before September 21, 2007, its comments and recommendations concerning Scientific's proposals and any alternative solutions to the problems Scientific was experiencing in attempting to comply with the Commission-required bonding requirement.

On September 6, 2007, Scientific filed its further progress report regarding the nine system improvements required by Decretal Paragraph No. 1 of the August 6, 2007 Order and requested an extension of time to file its proposal for a stepped-in rate increase as required by Decretal Paragraph No. 2 of that same Order.

On September 18, 2007, the Commission issued an Order granting Scientific's request for an extension of time to file its draft proposal for a stepped-in rate increase. That Order allowed Scientific to file such proposal by December 18, 2007.

On September 21, 2007, the Public Staff filed its comments and recommendation concerning the bonding requirement for the contiguous extension of sewer service in Maynard Manor Subdivision.

On October 29, 2007, the Commission issued an Order Requiring Bond in the above-captioned dockets requiring that Scientific post a bond in the amount of $10,000 in connection with the extension of sewer utility service in Maynard Manor Subdivision in Onslow County, North Carolina. Said Order stated that, upon Commission approval of the bond, surety, and commitment letter, a further order would be issued recognizing such contiguous extension. In addition, the October 29, 2007 Order required, among other things, that Scientific complete all the Commission-required improvements to its water and sewer systems in accordance with Decretal Paragraph No. 4 of the February 10, 2006 Order issued in these dockets and post the aforementioned $10,000 bond prior to extending water or sewer service into any of its other contiguous territories.

On December 14, 2007, a letter of credit and a commitment letter from First Citizens Bank were filed on behalf of Scientific.

On December 18, 2007, Scientific filed its Plan for Completing Required System Improvements (Plan).

On January 18, 2008, the Public Staff filed its response to Scientific's Plan.

On February 21, 2008, Scientific filed, in Docket No. W-176, Sub 29, a completed bond in the format of Appendix A-2 as attached to the Commission's February 10, 2006 Order.

CONTIGUOUS EXTENSION OF SEWER SERVICE IN MAYNARD MANOR SUBDIVISION

In its notification form filed on March 27, 1997, in Docket No. W-176, Sub 29, Scientific indicated that the proposed contiguous extension of sewer service into Maynard Manor Subdivision was intended to result in service to 122 connections and that such service area was contiguous to a currently franchised development, specifically, Deerfield Subdivision, and, thereby, Lauradale Subdivision as shown on Exhibit 6 (a Location Map [No Scale]), attached to its notification form.

Public Staff Utilities Engineer Jerry H. Tweed testified in Docket No. W-176, Sub 32, a general rate case proceeding, that the Public Staff had filed a motion in Docket Nos. W-176, Subs 29 and 30, on June 12, 2002, seeking the entry of an order imposing a moratorium on new connections pending the completion of certain improvements and recommending bond. However, because of delays resulting from the proposed sale of Scientific's systems to the City of Jacksonville and other factors, the Commission never ruled on the Public Staff's motion. Further, witness Tweed testified that the Public Staff was no longer seeking a moratorium on new connections, but believed that Scientific should be required to post a bond as required by G.S. 62-110.3(b).

Public Staff witness Tweed testified in Docket No. W-176, Sub 32, that Scientific was serving 49 customers in Maynard Manor Subdivision (the area requested to be served by the contiguous extension) as of December 31, 2004, the updated test year period utilized in that general rate case proceeding. Further, witness Tweed testified that Scientific's existing sewer system was being used to provide sewer utility service to the 49 residential sewer customers located in Maynard Manor Subdivision and that such customers receive water service directly from Onslow County.

Scientific has the technical and managerial capacity to provide sewer utility service in Maynard Manor Subdivision. As the Commission discussed in the February 10, 2006 Order, in the section relating to the Evidence and Conclusions for Finding of Fact No. 6, Scientific is providing adequate water and sewer service to its customers as evidenced by the limited response to customer notice in Scientific's general rate case proceeding; however, the Commission pointed out that numerous improvements were needed to the water and sewer facilities in order to avoid potential serious service and environmental problems that might result in the assessment of administrative penalties by state regulatory agencies. Consequently, the Commission required in Decretal Paragraph No. 4 of the February 10, 2006 Order that Scientific file a report addressing the specific steps to be taken regarding such system improvements; including detailed cost information and estimated timeframes for completion of each step. Scientific's September 6, 2007 Report showed that some progress has been made on certain of the required improvements to Scientific's water and sewer systems. Further, in its Plan filed on December 18, 2007, Scientific indicated that it had retained the services of another consultant to assist the Company with the process of formulating a plan for completing the Commission-required system improvements.

In regard to the posting of a performance bond in the amount of $10,000 relating to Scientific's request for a contiguous extension of sewer service in Maynard Manor Subdivision as required in the October 29, 2007 Order, a letter of credit and a commitment letter from First Citizens Bank were filed on behalf of Scientific on December 14, 2007. On February 21, 2008, Scientific filed, in Docket No. W-176, Sub 29, a completed bond in the format utilized in Appendix A-2 as attached to the Commission's February 10, 2006 Order. Scientific has no other bonds posted for any of its service areas.

SCIENTIFIC'S PLAN

In its Plan filed on December 18, 2007, Scientific observed that the Commission's April 18, 2006 Order[1] required, among other things, that Scientific undertake nine specific system improvement projects[2]. Scientific's Plan provided the following information regarding the system improvement projects delineated in Items a through i in Decretal Paragraph No. 4 of the February 10, 2006 Order:

a. Placing the new high yield well into service, including obtaining plan approval, removing the drying bed from well site radius, building a well house with any required treatment, installing a generator with automatic transfer switch, and installing a water line to connect the well to the distribution system.

Regarding Item a, Scientific remarked that it had managed to fund the estimated $85,000 needed to complete said project and that the project was estimated to be completed on or before January 30, 2008. Scientific commented that the system improvement project described in Item a was the only Commission-required system improvement to its water system. Scientific requested that the Commission grant a stepped-in water rate increase to allow the Company to begin recovering the cost of this improvement. Scientific explained that it planned to file a formal request for such relief once final cost data for this system improvement was available.

Scientific commented that the remaining eight Commission-required system improvements listed hereinbelow, as Items b through i, relate to its sewer system. Scientific noted that two of the projects, specifically Items d and f, have been completed and that an estimated $190,000 will be needed to complete the remaining six projects. Scientific maintained that it has been unable to obtain funding to complete said improvements in a timely manner; consequently, the Company has requested that the Commission approve a surcharge to provide the necessary funding. Specifically, Scientific requested a $4.00 per customer, per month surcharge for a 30-month period to generate approximately $192,000 (1,600 sewer customers x $4.00 x 30 months). Scientific contended that the surcharge revenues would be kept in a

[1] On February 10, 2006, the Commission issued a Recommended Order in these dockets granting partial rate increase; closing Docket No. W-176, Sub 30; requiring bond; and requiring further action by Scientific with respect to certain items as set forth in the decretal paragraphs of said Order. On April 17, 2006, the Commission issued an Order Overruling Exceptions and Affirming Recommended Order, and on April 18, 2006, the Commission issued an Order Approving Final Rates and Requiring Notice in these dockets.

[2] These nine system improvement projects were described in Items a through i in Decretal Paragraph No. 4 of the February 10, 2006 Order.

separate fund and used solely for the specified capital improvements. Scientific maintained that accounting reports of the collection and reimbursement of such funds would be provided to the Public Staff and Commission. Further, Scientific remarked that, based upon an effective date of February 1, 2008 for the proposed surcharge, the completion schedule for each sewer project reflected below should be attainable.

b. Construction and rehabilitation of the existing and new sludge holding facilities, including the ability to thicken the sludge.

Scientific represented that the Item-b project could be completed by October 31, 2008, at an estimated cost of $35,000.

c. Removal of accumulated sludge from the polishing ponds and drying bed area.

Scientific maintained that the Item-c project could be completed by July 30, 2010, at an estimated cost of $50,000.

d. Providing DWQ approved operable alarm systems at the wastewater treatment plant and all sewer pump stations.

Scientific reported that the Item-d project required minimum funding and, consequently, it has been completed.

e. Rebuilding the facilities at the Deerfield sewer pump station.

Scientific proposed that the Item-e project could be completed by September 30, 2009, at an estimated cost of $70,000.

f. Installing a generator at the Maynard Manor sewer pump station.

Scientific stated that developer assistance has been obtained and, therefore, this Item-f project has been completed.

g. Repair or replacement of the influent bar screen at the wastewater treatment plant.

Scientific noted that the Item-g project could be completed by June 30, 2008, at an estimated cost of $12,000.

h. Repair of clogged or blown air diffusers at the wastewater treatment plant.

Scientific maintained that the Item-h project could be completed by November 30, 2009, at an estimated cost of $15,000.

i. Installation of a fence around the sludge drying facilities, unless the facilities are slated for abandonment.

Scientific remarked that the Item-i project could be completed by April 30, 2008, at an estimated cost of $7,500.

PUBLIC STAFF'S RESPONSE

In its January 18, 2008 Response, the Public Staff opposed Scientific's request that the Commission impose a monthly surcharge on Scientific's sewer customers. The Public Staff opined that Scientific's ratepayers should not be required to pay in advance for improvements to the sewer system that have not yet been completed. The Public Staff pointed out that the Commission had stated the following in its February 10, 2006 Order:

> The ratemaking procedure set out in G.S. 62-133 establishes a clear distinction between the role of the utility customer and the role of the investor. Customers are required to pay rates sufficient to cover the utility's reasonable operating expenses and provide a fair return on invested capital. On the other hand, the responsibility for providing capital to construct or expand the utility system, or to replace equipment that has worn out or malfunctioned, is upon the investor. When customers are asked to contribute capital to the utility – whether by assessing them directly for construction costs, or by including in rate base capital costs that have not in fact incurred – the roles of the customer and investor are distorted.

The Public Staff asserted that it does not believe that the proposed surcharge is necessary to fund the required improvements and opined that current rates and investment from the shareholders should be sufficient to complete the Commission-required improvements. The Public Staff pointed out that Ben Aragona, President of Scientific, testified in Docket Nos. W-176, Subs 29, 30, and 32, that the Company had hired a new employee at an annual salary of $35,000, and that such new employee "is a welder and pipe fitter. And there's a lot to that in waste water treatment facility, especially." The Public Staff maintained that the Commission included the salary expense of such new employee in determining Scientific's cost of service and the underlying rates approved in its February 10, 2006 Order. Consequently, the Public Staff questioned why Scientific would need additional funding from the ratepayers to contract with a welder to perform the Commission-required improvements to its sewer systems when the salary of a full-time welder and pipe-fitter was included in the cost of service and reflected in rates.

Although it opposed Scientific's request for a surcharge, the Public Staff stated that it remained unopposed to Scientific making a detailed and thorough proposal regarding stepped-in rates or proposing any other innovative plan for making the required improvements. The Public Staff argued that Scientific's Plan was wholly inadequate to address the concerns of the Public Staff and that, without having received additional detailed information, the Public Staff was unable to support such a plan. Consequently, the Public Staff agreed that an informal conference with Scientific, the Public Staff, and the Commission Staff could be productive provided that Scientific was prepared to provide sufficient detail, including actual, detailed price estimates and timetables from vendors, rather than internal estimates.

Lastly, the Public Staff suggested that the proposed conference should include a 20 to 30 minute presentation by the Company that further explains in detail: (1) the Company's proposal for a stepped-in rate increase; (2) how a stepped-in rate increase would advance Scientific's progress in making the required improvements; and (3) any other proposals that might assist Scientific in completing the Commission-required improvements. The Public Staff further suggested that, following Scientific's presentation, either the Commission Staff or the Public Staff should be allowed to ask questions or otherwise be heard. The Public Staff asserted that it did not intend to make any presentation or assist Scientific in making its presentation at the aforementioned proposed conference.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the foregoing and the entire record in these proceedings, the Commission finds and concludes that Scientific has the technical and managerial capacity to continue providing sewer utility service in Maynard Manor Subdivision; that Scientific is providing adequate water and sewer service to its customers as evidenced by the limited response to the customer notice in Scientific's last general rate case proceeding; that no evidence has been presented that indicates that Scientific's level of service has deteriorated or otherwise changed since that general rate proceeding; and that Scientific has made significant progress toward completing certain of the Commission-required improvements to its water and sewer systems. Further, the Commission recognizes that, after the conclusion of its general rate case proceeding, Scientific retained the services of another consultant to assist the Company with the process of formulating a plan for completing the Commission-required system improvements that could ultimately be approved by the Commission. Consequently, the Commission is of the opinion that the notification to provide sewer utility service into Maynard Manor Subdivision meets the Commission's criteria for such extension and should be recognized and that the rates approved by the Commission for Scientific's other franchised areas should be approved for such extension.

In addition, with respect to the posting of a performance bond in the amount of $10,000 relating to Scientific's request for a contiguous extension of sewer service into Maynard Manor Subdivision, as required in the October 29, 2007 Order, the Commission finds and concludes that the letter of credit surety and commitment letter filed in this proceeding satisfy the requirements of that Order and should be approved.

Regarding Scientific's request that the Commission approve a $4.00 per customer per month surcharge for a 30-month period to generate approximately $192,000 in funding for the Commission-required improvements to its sewer systems, the Commission finds and concludes that such request should be denied. As the Commission stated in its February 10, 2006 Order issued in these dockets, the ratemaking procedure set out in G.S. 62-133 establishes a clear distinction between the role of the utility customer and the role of the investor. In particular, customers are required to pay rates sufficient to cover the utility's reasonable operating expenses and provide a fair return on invested capital. On the other hand, the responsibility for providing capital to construct or expand the utility system, or to replace equipment that has worn out or malfunctioned, is placed upon the investor.[1] When customers are asked to contribute capital to the utility – whether by direct assessments for construction costs, or by including in rate base capital costs that have not in fact been incurred – the roles of the customer and investor become distorted. Additionally, as stated in the February 10, 2006 Order, the Commission observed that there is one situation in which the utility's customers may be assessed for capital costs. Specifically, under G.S. 62-118(b) and (c), if there is an "imminent danger of losing adequate water or sewer service or the actual loss thereof," and "there is no reasonable probability of the owner or operator of such utility obtaining the capital necessary to improve or replace the facilities from sources other than the customers," the Commission may assess customers for these costs. The statutes contemplate that such an assessment should be regarded as a last resort, to be undertaken only after an emergency has arisen, and ordinarily only when control of the system has been turned over to an emergency operator. At this time, the Commission finds that no evidence has been presented which indicates that such an emergency exists and reaffirms the findings and conclusions contained in its February 10, 2006 Order. Absent the necessity for appointing an emergency operator, the Commission concludes that there is no legal basis for assessing the customers directly for Scientific's proposed construction costs and that, consequently, Scientific's request for a surcharge should be denied.

At this juncture, the Commission believes that it is in the best interests of the Company and its customers for the Company and the Public Staff to participate in an informal conference for the purpose of allowing Scientific and its consultant an opportunity to present a proposal for a stepped-in rate increase and any other proposals that might be appropriate for the purpose of assisting Scientific in making the required system improvements. In addition, such presentation should include a proposal for the stepped-in water rate increase requested by Scientific in its Plan regarding the approximately $85,000 it funded with respect to the water system improvement project discussed hereinbefore. As indicated in the Evidence and Conclusions for Finding of Fact No. 7 of the Commission's February 10, 2006 Order, such proposal should specify the date when each increase should take effect, the amount of the increase in each customer's rates, and the total amount of each increase, or, if the timing and amount of the increases are subject to contingencies, the proposal should provide clear and unambiguous criteria for determining when increases should be effective and how the amount of an increase should be determined. If the proposal is tied to a loan agreement, the provisions of the loan agreement must be made available for the Public Staff's review. The Commission concludes that such conference should begin with a 20 to 30 minute presentation by the Company that further explains in detail: (1) the Company's proposal for a stepped-in rate increase; (2) how a stepped-in rate increase would advance Scientific's progress in making the required improvements; and (3) any other proposals that might assist Scientific in completing the Commission-required improvements.

IT IS, THEREFORE, ORDERED as follows:

1. That the letter of credit surety and commitment letter filed in this proceeding for the bond amount of $10,000 required by the Commission are accepted and approved.

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[1] In some instances, customers are required to pay tap fees that serve to reimburse investors for their capital investments and are accounted for as contributions in aid of construction. Nevertheless, the primary responsibility for providing funds for plant construction and other capital projects rests upon the investor.

2. That the contiguous extension of sewer utility service into Maynard Manor Subdivision in Onslow County, North Carolina is recognized as meeting the Commission's criteria for such extension.

3. That Appendix A constitutes the Certificate of Public Convenience and Necessity to provide sewer utility service in Maynard Manor Subdivision.

4. That the Schedule of Rates approved in the Commission's Order Approving Final Rates and Requiring Notice issued on April 18, 2006 is approved for Scientific for sewer utility service in Maynard Manor Subdivision. These are the same rates approved by the Commission for Scientific's other franchised areas.

5. That Docket No. W-176, Sub 29 shall be, and hereby is, closed.

6. That Scientific's request for approval of a surcharge to fund the remaining Commission-required improvements to its sewer system is hereby denied for the reasons stated herein.

7. That Scientific shall meet with the Public Staff on or before June 30, 2008, to present its detailed proposal for a stepped-in rate plan to fund the remaining Commission-required improvements to its sewer systems. Such plan shall include Scientific's proposal regarding the approximately $85,000 Scientific is seeking to recover in a stepped-in water rate increase related to the water system improvement projects[1], described herein, that Scientific completed and funded earlier this year. Said plan shall specify the date when each proposed increase would take effect, the amount of the increase in each customer's rates, and the total amount of each increase, or, if the timing and amount of the increases are subject to contingencies, the plan shall provide clear and unambiguous criteria for determining when any proposed increases would become effective and how the amount of any proposed increase would be determined. If the plan is tied to a loan agreement, the provisions of the loan agreement must be made available for the Public Staff's review.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of April, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh042408.01

[1] Item a, Decretal Paragraph No. 4 of the February 10, 2006 Order.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-176, SUB 29

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

SCIENTIFIC WATER AND SEWERAGE CORPORATION

is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

for providing sewer service

in

MAYNARD MANOR SUBDIVISION

Onslow County, North Carolina

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the _24th_ day of _April, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. W-1013, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Carolina Trace Utilities, Inc., 2335	)	ORDER GRANTING
Sanders Road, Northbrook, Illinois 60062, for	)	PARTIAL RATE INCREASE
Authority to Increase Rates for Water and Sewer	)	AND REQUIRING CUSTOMER
Utility Service in the Carolina Trace Development in	)	NOTICE
Lee County, North Carolina	)	

HEARD IN: Sanford Municipal Building, Council Chambers, 225 E. Weatherspoon Street, Sanford, North Carolina on Tuesday, September 23, 2008, at 10:00 a.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, October 21, 2008, at 9:30 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; Commissioner Howard N. Lee; and Commissioner William T. Culpepper, III

APPEARANCES:

For Carolina Trace Utilities, Inc.:

Christopher J. Ayers, Hunton & Williams, LLP, Post Office Box 109, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Tab C. Hunter, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On April 24, 2008, Carolina Trace Utilities, Inc. (Applicant or Carolina Trace), filed a letter notifying the Commission of its intent to file a general rate case as required by Commission Rule R1-17(a).

On May 23, 2008, Carolina Trace filed an application with the Commission seeking authority to increase its rates for water and sewer utility service in the Carolina Trace Development in Lee County, North Carolina. On that same date, the Applicant filed a confidential attachment to its application. On May 27, 2008, Carolina Trace filed an amendment to its application.

The Applicant serves approximately 1,486 water customers and 1,437 sewer customers. The present rates for water and sewer utility service have been in effect since February 1, 1995.[1]

By Order dated June 17, 2008, the Commission declared the above-captioned proceeding to be a general rate case pursuant to G.S. 62-137; suspended the proposed new rates for a period of up to 270 days pending further investigation and hearing; and scheduled this matter for hearing in Sanford and Raleigh, North Carolina. The Applicant was required to provide customer notice of the hearings and the proposed rate increase to all customers.

On June 27, 2008, the Commission issued an Order Rescheduling Hearing and Requiring Customer Notice due to a scheduling conflict related to the Sanford, North Carolina customer hearing.

On July 11, 2008, the Applicant filed its Certificate of Service indicating that notice was provided as required by the June 27, 2008 Order.

The North Carolina Utilities Commission Public Staff (Public Staff) received protests from 196 customers prior to the public hearing held on September 23, 2008. Such customer communications protested, in the form of petitions, individual letters, form letters, and emails, the magnitude of the proposed rate increase.

On September 8, 2008, the Applicant prefiled the testimony of Pauline M. Ahern, Principal, AUS Consultants, and Lena Georgiev, Manager of Regulatory Affairs, Utilities, Inc. On September 11, 2008, the Applicant prefiled the testimony of John D. Williams, Director of Governmental Affairs, Utilities, Inc.

On September 23, 2008, a public hearing for the purpose of receiving customer testimony was held in the Sanford Municipal Building, Council Chambers, 223 E. Weatherspoon Street, Sanford, North Carolina as scheduled. A total of 35 customers presented testimony at the public hearing or asked that their written letters to the Public Staff be entered into the record.

On September 24, 2008, Carolina Trace, CWS Systems, Inc., Carolina Water Service, Inc. of North Carolina, and the Public Staff filed a Partial Settlement Agreement in Docket Nos. W-1013, Sub 7; W-778, Sub 81; and W-354, Sub 314, which stipulated to the appropriate capital structure and cost rates for the components of the capital structure and return on rate base for said proceedings.

On September 30, 2008, the Public Staff filed a motion for extension of time to file its testimony.

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[1] In Docket No. W-1013, Sub 1, a Recommended Order Granting Partial Rate Increase was issued on January 30, 1995. On February 1, 1995, the Commission issued an Order Allowing Recommended Order to Become Effective. On August 9, 1996, in Docket No. W-1013, Sub 2, an Order Approving Tariff Revision and Refund Plan was issued amending Carolina Trace's schedule of rates to delete the tariff provision requiring the EPA surcharge and approving a refund plan for refunding the excess EPA surcharge revenue collected by Carolina Trace. On January 24, 1997, in Docket No. W-1013, Sub 3, an Order Revising Tariffs was issued that deleted all references to gross-up on contributions in aid of construction to reflect the cessation of the collection of gross-up on contributions collected by water and sewer companies after June 12, 1996, pursuant to the Commission's August 27, 1996 Order in Docket No. M-100, Sub 113.

On October 1, 2008, the Commission issued an Order Granting Motion for Extension of Time to File Testimony.

On October 15, 2008, the Public Staff verbally requested a one-day extension of time to file its testimony. In support of its request, the Public Staff stated that the parties were attempting to reach a settlement in this proceeding. On that same date, the Commission issued an Order Granting Extension of Time.

On October 16, 2008, the Public Staff prefiled the Testimony and Exhibits of O. Bruce Vaughan, Utilities Engineer, Water Division.

On October 20, 2008, the Applicant and the Public Staff filed a Stipulation that settled the outstanding issues between the two parties. However, the Stipulation reflected that the stipulating parties agreed to amend this Stipulation and the corresponding exhibits and schedules to include the costs of the Laurel Thicket Pump Station project in rate base if such costs could be adequately documented and provided to the Public Staff by October 31, 2008. In addition, the stipulating parties also agreed to upwardly adjust the Applicant's revenue requirement to reflect the inclusion of additional rate case costs incurred by Carolina Trace as long as Carolina Trace could provide complete documentation of the actual costs to the Public Staff by October 31, 2008.

Also, on October 20, 2008, Kirt L. Ervin, an engineer with Utility Service Co., filed a letter with the Commission stating that the final on-site inspection had been completed related to the exterior renovation of the 150,000 elevated tank serving Carolina Trace's water system.

On October 21, 2008, the Applicant filed a report addressing the service-related complaints expressed at the public hearing held in Sanford, North Carolina, on September 23, 2008.

Also, on October 21, 2008, an evidentiary hearing was held at the North Carolina Utilities Commission hearing room in Raleigh, North Carolina, as scheduled. No public witnesses testified. The Public Staff presented the testimony of Katherine A. Fernald, Water Supervisor, Public Staff Accounting Division, and O. Bruce Vaughan, Utilities Engineer, Public Staff Water Division.

On November 20, 2008, the Applicant and the Public Staff filed an Amended Stipulation, including Exhibits I and II, to reflect the effect of updating certain capital project costs and expenses relating to the Laurel Thicket Pump Station project and rate case expenses. The Amended Stipulation contained the final, adjusted rates and charges agreed to by the Applicant and the Public Staff.

On November 21, 2008, the Applicant and the Public Staff filed a Joint Proposed Order.

On the basis of the application, the Partial Settlement Agreement, the Stipulation, the Amended Stipulation, and the other evidence of record, the Commission is of the opinion that the provisions of the Amended Stipulation are just and reasonable and that the Commission should make the following

FINDINGS OF FACT

1. Carolina Trace is a corporation duly organized under the law of and authorized to do business in the State of North Carolina. Carolina Trace is a franchised public utility providing water and sewer utility service to customers in the Carolina Trace Development in Lee County, North Carolina.

2. Carolina Trace is properly before the Commission, pursuant to Chapter 62 of the North Carolina General Statutes, for a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer utility operations.

3. Carolina Trace provides service to approximately 1,486 water customers and 1,437 sewer customers.

4. The test period appropriate for use in this proceeding is the 12 months ended December 31, 2007.

5. The overall quality of service provided by Carolina Trace is adequate.

6. A significant number of customers filed position statements with the Commission protesting the magnitude of the proposed rate increase. At the customer hearing held in Sanford, North Carolina, a total of 35 customers presented testimony or asked that their written letters to the Public Staff be entered into the record. The service concerns expressed by the public witnesses included, but were not limited to, the frequency of water main breaks; the need for improvements in completing the road repairs which are necessary following main repairs and water tap installations; gaps in wastewater structures which may allow sewage to flow into the lake; the fact that surface water entering the wastewater mains through manholes has occasionally overwhelmed the capacity of the wastewater treatment plant; failure to alert the volunteer fire department when a large main break occurred; the need for a standby generator to maintain water supply in case of an emergency; health concerns prompted by the required public notices sent following the periodic exceedance of disinfection byproducts, maximum contaminant limits; and failure to provide advance notice regarding sewer right-of-way clearings. No public witnesses testified at the evidentiary hearing in Raleigh, North Carolina.

7. Carolina Trace filed a report with the Commission on October 21, 2008, addressing the service-related concerns expressed by the public witnesses who testified at the customer hearing held in Sanford, North Carolina. Such report described each of the witnesses' specific service-related concern(s), the Applicant's response, and how each concern was addressed, if applicable.

8. Carolina Trace's present and proposed water and sewer utility service rates are as follows:

Monthly Metered Water Utility Service	Present Rates	Proposed Rates
Base charge, zero usage	$ 9.95 minimum	$ 15.14 minimum
Usage charge, per 1,000 gallons	$ 3.62	$ 5.51

Monthly Metered Sewer Utility Service				
Base charge, zero usage	$15.00	minimum	$36.37	minimum
Usage charge, per 1,000 gallons	$ 4.02		$ 9.75	minimum

9. Carolina Trace requested an increase in its water and sewer rates that would produce additional revenues of $230,294 for water operations and $686,902 for sewer operations.

10. The Applicant's original cost rate base at December 31, 2007, for use in this proceeding is $596,941 for water operations and $4,499,316 for sewer operations.

11. Carolina Trace had water plant in service of $1,086,760 and sewer plant in service of $2,673,272 at the end of the test year.

12. The accumulated depreciation at the end of the test year was $250,293 for water operations and $702,068 for sewer operations.

13. The contributions in aid of construction at the end of the test year were $422,117 for water operations and $602,434 for sewer operations, reduced by accumulated amortization of $41,867 for water operations and $196,355 for sewer operations.

14. The pro forma plant, net of accumulated depreciation, included in the Applicant's rate base is $7,458 for water operations and $3,534,066 for sewer operations.

15. Carolina Trace is entitled to total rate case costs of $77,712, consisting of $1,349 in costs to mail notices, $57,958 in Water Service Corporation personnel costs, $14,570 in legal fees, $3,486 in cost of capital witness costs, and $349 in miscellaneous costs. These total rate case costs should be amortized over five years, resulting in an annual level of rate case expense of $15,542.

16. It is appropriate to calculate regulatory fees using the statutory rate of 0.12%.

17. It is appropriate to calculate gross receipts taxes based upon the approved levels of revenues and the statutory rates of 4% for water operations and 6% for sewer operations.

18. It is appropriate to calculate state and federal income taxes based upon the corporate rates of 6.9% for state income taxes and 34% for federal income taxes.

19. Carolina Trace's total operating revenue deductions under present rates are $530,885 for water operations and $490,419 for sewer operations.

20. Carolina Trace's present rates produce total operating revenues of $446,045 for water operations and $487,262 for sewer operations.

21. The appropriate overall rate of return on rate base is 8.36%, which is based upon a capital structure of 54% long-term debt, with an embedded cost of debt of 6.58%, and 46% common equity, with a return on common equity of 10.45%.

22. The Applicant is entitled to changes in rates that will produce operating revenues of $605,358 for water operations and $1,035,849 for sewer operations.

23. The rates, as provided in Stipulation Exhibit II (A) attached to the Amended Stipulation, will produce additional revenues of $159,314 for water operations and $548,587 for sewer operations.

24. Carolina Trace's total operating revenue deductions under the stipulated rates, excluding gross receipts tax, regulatory fees, and income taxes are $555,453 for water operations and $659,697 for sewer operations.

25. The water and sewer utility service rates and charges agreed to by the Applicant and the Public Staff are as follows:

Monthly Metered Water Utility Service:

Base Charge, zero usage	$13.54 minimum
Usage Charge, per 1,000 gallons	$ 4.93

Monthly Metered Sewer Utility Service: [1/, 2/]

Base Charge, zero usage	$32.07 minimum
Usage Charge, per 1,000 gallons	$ 7.59

1/ Residential sewer usage bills are based on metered water usage and are limited to payment for 10,000 gallons per month, i.e., "Usage Charges" may not exceed $75.90 (for 10,000 gallons), with total sewer bill not to exceed $107.97.

2/ Commercial sewer usage bills are based on total metered water usage, i.e., are not limited to a maximum volume or charge.

Tap-on Fee:

Water Utility Service Connection	$605.00
Sewer Utility Service Connection	$533.00

Reconnection Charge:

If water service is cut off by utility for good cause:	$27.00
If water service is cut off by utility at customer's request:	$27.00
If sewer service is cut off by utility for good cause by any method other than above:	Actual Cost

New Customer Charge:

Water Utility Service	$27.00
Sewer Utility Service	$27.00 [3/]

3/ This charge will be waived if sewer customer is also a water customer.

Meter Testing Fee:

Testing requested by customer once in 24 months	No Charge
Testing requested by customer more than once in 24 months	$20.00

Returned Check Charge: $10.00

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

26. The rates agreed to by Carolina Trace and the Public Staff, as provided hereinabove and included in Appendix A, attached hereto, are just and reasonable and should be approved.

27. Carolina Trace and the Public Staff have agreed to an excess capacity percentage of 15%, which equates to 400 gallons per day per customer.

28. Carolina Trace should continue to maintain system log books or system files that account for equipment maintenance and repair, water line issues and corrective actions, and sewer line issues and corrective actions, as stipulated.

29. Carolina Trace should continue to maintain a customer log showing customer complaints and requests and the Applicant's responses, as well as special disconnection requirements due to seasonal usage or other reasons, as stipulated.

30. Carolina Trace should develop a procedure for providing advance notice to customers of events such as planned or extended outages, and property encroachments for the purposes of surveys, troubleshooting, preventive maintenance, or other reasons, as stipulated.

31. Carolina Trace should revise its tariff such that the sewer billing exclusion for volumes in excess of 6,000 gallons for commercial customers is removed, and the sewer billing exclusion for residential customer volumes is increased from 6,000 gallons to 10,000 gallons, as stipulated.

32. The Applicant and the Public Staff have agreed to waive their respective right of appeal from a final Order of the Commission incorporating the matters stipulated in the Amended Stipulation.

33. The Amended Stipulation contained the provision that Carolina Trace and the Public Staff agreed that none of the positions, treatments, figures or other matters reflected in said Amended Stipulation should have any precedential value, nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter in issue.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

Pursuant to the Stipulation entered and filed on September 24, 2008, the Applicant agreed to file a report on all service-related issues in this proceeding by the date of the evidentiary hearing in Raleigh, North Carolina. On October 21, 2008, Carolina Trace filed a report addressing service-related complaints expressed at the public hearings. No party has contested the contents of that report. The Commission believes that the October 21, 2008 filing by Carolina Trace has adequately addressed the service-related concerns expressed by all the public witnesses.

The Commission recognizes that the Applicant's present water and sewer rates have been in effect for over 13 years, as the last general rate increase approved by the Commission for Carolina Trace became effective on February 1, 1995. Due to the passage of time since its last rate case proceeding and due to various significant capital improvements which have recently been placed into service to address specific wastewater service-quality concerns expressed by Carolina Trace's customers and/or the North Carolina Department of Environment and Natural Resources, Division of Water Quality (DWQ), regarding plant reliability, the overall quality of service, and the absence of onsite backup/emergency power, the Company has experienced significant increases in the cost of providing service since 1995. In particular, on August 12, 2008, Carolina Trace placed into service a newly constructed 350,000 gallon wastewater treatment plant (WWTP) and began using the older WWTP for flow equalization purposes to provide Carolina Trace with the additional capacity needed to avoid exceeding its permitted monthly average flow limit, which has resulted in many cited violations from DWQ in the past three years. In addition, the Company has added a 400-kilowatt, diesel-fueled generator with automatic controls which activate the generator in the event of a power outage; the Company has made significant improvements to the Laurel Thicket Pump Station; and the Company has installed a new computer system to upgrade its general ledger and billing systems which benefits both the water and wastewater operations. The Commission concludes that general increases in overall operating expenses since 1995 and the significant capital improvements recently placed into service by the Company are the primary reasons for the water and sewer rate increases recommended in the stipulating parties' Amended Stipulation and approved by the Commission in this Order.

Based upon the foregoing findings of fact and the entire record in this proceeding, the Commission is of the opinion that the stipulated rates should be approved and that the provisions of the Partial Settlement Agreement filed on September 24, 2008, and the provisions of the Amended Stipulation between Carolina Trace and the Public Staff filed on November 20, 2008, which are incorporated by reference herein, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

2. That the Schedule of Rates is hereby authorized to become effective for service rendered on and after the issuance date of this Order.

3. That a copy of the Notice to Customers, attached hereto as Appendix B, shall be mailed with sufficient postage or hand delivered to all affected customers in conjunction with the next regularly scheduled billing process.

4. That the Applicant shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance date of this Order.

5. That the Amended Stipulation between the parties to this proceeding as well as the Partial Settlement Agreement, incorporated by reference, herein, are hereby approved.

6. That neither the Amended Stipulation entered on November 20, 2008, nor this Order shall be cited or treated as precedent in future proceedings.

7. That Carolina Trace shall continue to maintain system log books or system files that account for equipment maintenance and repair, water line issues and corrective actions, and sewer line issues and corrective actions.

8. That Carolina Trace shall continue to maintain a customer log showing customer complaints and requests and company responses, as well as special disconnection requirements due to seasonal usage or other reasons.

9. That Carolina Trace shall develop a procedure for providing advance notice to customers of events such as planned or extended outages and property encroachments for the purposes of surveys, troubleshooting, preventive maintenance, or other reasons.

10. That Carolina Trace shall revise its tariff such that the sewer billing exclusion for volumes in excess of 6,000 gallons for commercial customers is removed, and the sewer billing exclusion for residential customer volumes is increased from 6,000 gallons to 10,000 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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APPENDIX A
PAGE 1 OF 3

SCHEDULE OF RATES

for

CAROLINA TRACE UTILITIES, INC.

for providing water and sewer utility service in

CAROLINA TRACE DEVELOPMENT

Lee County, North Carolina

Monthly Metered Water Utility Service:

WATER AND SEWER – RATE INCREASE

Base charge, zero usage	$13.54 minimum
Usage charge, per 1,000 gallons	$ 4.93

Monthly Metered Sewer Utility Service: [1/,2/]

Base Charge, zero usage	$32.07 minimum
Usage Charge, per 1,000 gallons	$ 7.59

1/ Residential sewer usage bills are based on metered water usage and are limited to payment for 10,000 gallons per month, i.e., "Usage Charges" may not exceed $75.90 (for 10,000 gallons), with total sewer bill not to exceed $107.97.

2/ Commercial sewer usage bills are based on total metered water usage, i.e., are not limited to a maximum volume or charge.

Tap-on Fee:

Water service connection	$605.00
Sewer service connection	$533.00

Reconnection Charge:

If water service is cut off by utility for good cause	$ 27.00
If water service is cut off by utility at customer's request	$ 27.00
If sewer service cut off by utility for good cause by any method other than above	Actual Cost

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Reconnection Charge (cont.):

If payment for water and/or sewer utility service is not received by the past-due date, a customer may, in addition to all past-due and current charges, have to pay late payment finance charges in order to avoid having water and/or sewer service disconnected.

To resume water and/or sewer utility service after discontinuance for good cause, a customer must pay the reconnection charge(s) discussed above, plus any delinquent water and/or sewer bill(s), including finance charges.

Rule R10-16(f): Whenever sewer service is discontinued for any reason the utility shall send a report of termination of service to the local county board of health.

Neglect or failure to pay amounts due or to otherwise comply with provisions of this tariff shall be deemed to be sufficient cause for discontinuance of service. Prior to disconnection, Carolina Trace Utilities, Inc. (CTU), will diligently try to induce the customer to pay or otherwise comply with the tariff. After such effort, CTU will provide to the customer written notice of at least five days (excluding Sundays and holidays) prior to disconnection. Such notice will contain, at a minimum, a copy of this provision, and a description of the procedures which CTU will perform to discontinue service.

In the event that an emergency or dangerous condition is found to exist, or fraudulent use of the wastewater system is detected, sewer utility service may be cut off without such notice. In such an event, notice as described above will be given as soon as possible.

If discontinuance of sewer service becomes necessary, CTU will install a valve or other device to cut off and/or block the sewer line. Prior to installing the valve or device, CTU will provide to the customer a detailed good faith estimate of the actual cost of disconnection.

New Customer Charge:

Water utility service	\$27.00
Sewer utility service	\$27.00 [3/]

[3/] This charge will be waived if sewer customer is also a water customer.

APPENDIX A
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Meter Testing Fee:

Testing requested by customer once in 24 months	No Charge
Testing requested by customer more than once in 24 months	\$20.00

If the meter is found to register in excess of the prescribed accuracy limits, the testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge will be due, i.e., retained by CTU.

Returned Check Charge:	\$10.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1013, Sub 7, on this the 19th day of December, 2008.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B
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DOCKET NO. W-1013, SUB 7

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Carolina Trace Utilities, Inc., 2335	)	
Sanders Road, Northbrook, Illinois 60062, for	)	**NOTICE TO CUSTOMERS**
Authority to Increase Rates for Water and Sewer	)	
Utility Service in the Carolina Trace Development in	)	
Lee County, North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Trace Utilities, Inc., to charge increased rates for water and sewer utility service in all of its service areas in Lee County, North Carolina. The new approved rates are as follows:

Monthly Metered Water Utility Service:

Base charge, zero usage	\$13.54 minimum
Usage charge, per 1,000 gallons	\$ 4.93

Monthly Metered Sewer Utility Service: 1/, 2/

Base charge, zero usage	\$32.07 minimum
Usage charge, per 1,000 gallons	\$ 7.59

1/ Residential sewer usage bills are based on metered water usage and are limited to payment for 10,000 gallons per month, i.e., "Usage Charges" may not exceed \$75.90 (for 10,000 gallons), with total sewer bill not to exceed \$107.97.

2/ Commercial sewer usage bills are based on total metered water usage, i.e., are not limited to a maximum volume or charge.

Tap-on Fee:

Water service connection	\$605.00
Sewer service connection	\$533.00

APPENDIX B
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Reconnection Charge:

If water service is cut off by utility for good cause $\quad$ \$ 27.00

If water service is cut off by utility at customer's request	$ 27.00
If sewer service cut off by utility for good cause by any method other than above	Actual Cost

If payment for water and/or sewer utility service is not received by the past-due date, a customer may, in addition to all past-due and current charges, have to pay late payment finance charges in order to avoid having water and/or sewer service disconnected.

To resume water and/or sewer utility service after discontinuance for good cause, a customer must pay the reconnection charge(s) discussed above, plus any delinquent water and/or sewer bill(s), including finance charges.

Rule R10-16(f): Whenever sewer service is discontinued for any reason the utility shall send a report of termination of service to the local county board of health.

Neglect or failure to pay amounts due or to otherwise comply with provisions of this tariff shall be deemed to be sufficient cause for discontinuance of service. Prior to disconnection, Carolina Trace Utilities, Inc. (CTU), will diligently try to induce the customer to pay or otherwise comply with the tariff. After such effort, CTU will provide to the customer written notice of at least five days (excluding Sundays and holidays) prior to disconnection. Such notice will contain, at a minimum, a copy of this provision, and a description of the procedures which CTU will perform to discontinue service.

In the event that an emergency or dangerous condition is found to exist, or fraudulent use of the wastewater system is detected, sewer utility service may be cut off without such notice. In such an event, notice as described above will be given as soon as possible.

If discontinuance of sewer service becomes necessary, CTU will install a valve or other device to cut off and/or block the sewer line. Prior to installing the valve or device, CTU will provide to the customer a detailed good faith estimate of the actual cost of disconnection.

APPENDIX B
PAGE 3 OF 3

New Customer Charge:

Water utility service	$27.00
Sewer utility service	$27.00 [3/]

[3/] This charge will be waived if sewer customer is also a water customer.

Meter Testing Fee:

Testing requested by customer once in 24 months	No Charge

Testing requested by customer more than once in 24 months $20.00

If the meter is found to register in excess of the prescribed accuracy limits, the testing charge will be waived. If the meter is found to register accurately or below prescribed accuracy limits, the charge will be due, i.e., retained by CTU.

Returned Check Charge:	$10.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

CERTIFICATE OF SERVICE

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1013, Sub 7, and the Notice was mailed or hand delivered by the date specified in the Order.

By: ______________________________

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ____________________ in Docket No. W-1013, Sub 7.

Witness my hand and notarial seal, this the _____ day of __________, 2008.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-1105, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Inquiry by Royal Palms Water and Sewer System, 5140	)	
Carolina Beach Road, Wilmington, North Carolina	)	ORDER DENYING
28412, Regarding Ability to Pass Through Back Charges	)	RECOMMENDATION
for Sewer Service from New Hanover County for Bulk	)	OF PUBLIC STAFF
Sewer Service Provided to Royal Palms Mobile Home	)	
Park in New Hanover County, North Carolina	)	

BY THE COMMISSION: On October 29, 2007, Kenneth C. Burnham, President of Royal Palms Water and Sewer System (Royal Palms), filed a letter in this docket addressed to the Utilities Commission. The letter states that Royal Palms operates a small water and sewer system serving 192 mobile home sites in New Hanover County, that the system distributes water and sewer service purchased from New Hanover County (the County), that the County recently gave notice that it had misread the meters for Royal Palms' service "on the low side resulting in additional charges," that these charges are over $77,000 for the last three years, and that Royal Palms has insufficient funds to pay this amount without passing the charges through to customers. The letter then poses three questions:

1.) Are we allowed to pass this charge through to our customers???
2.) If we need your approval, what is the mechanism to be used (one time payment or monthly installments)??
3.) What is the approval process, and how long does it take?

The letter concludes, "Please respond promptly to this inquiry." No other filings have been made in this docket.

The Public Staff presented the letter to the Commission at the Staff Conference of April 7, 2008. The Public Staff stated that it had investigated the letter and had made certain "findings," which the Commission now summarizes as follows: Royal Palms Mobile Home Park, LLC, d/b/a Royal Palms Water and Sewer System, was granted a franchise to provide water and sewer utility service to customers in Royal Palms Mobile Home Park by Order dated July 30, 1998, in Docket No. W-1105, Sub 0. The water rates established in that docket were based on the cost of purchasing bulk water from Cape Fear Utilities. Cape Fear Utilities subsequently sold its system to the City of Wilmington, which now sells bulk water to Royal Palms. The sewer rate established in Docket No. W-1105, Sub 0 was based on Royal Palms's cost of operating an on-site wastewater treatment plant. In 1999, Royal Palms ceased using this wastewater treatment plant and connected to the New Hanover County sewer system as a bulk sewer customer at a rate of $498 bimonthly plus $2.87 per 1,000 gallons. As of July 1, 2006, the bulk rate increased to $548 bimonthly plus $3.25 per 1,000 gallons. Due to misreading the water meter, the County billed Royal Palms for sewer service at only one one-hundredth of its actual usage. Considering the base charge, the resulting bills were about one tenth of what they should have been. The County's bimonthly bills to Royal Palms averaged about $550; they should have been about $5,500. The County has now discovered the error and has back-billed Royal Palms for approximately $77,000 for the past three years' sewer service. Although the misreading went back to 1999, the County is back-billing for only three years due to the statute of limitations.

The Public Staff stated at Staff Conference that, in its view, a pass-through to customers of the $77,000 bill from the County would constitute unlawful ratemaking under Utilities Commission v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977). Moreover, the Public Staff stated that annual reports indicate that Royal Palms has received revenues well in excess of its major operating expenses since Royal Palms reduced its expenses by switching to bulk sewer service while maintaining the sewer rate that had been based upon operating a treatment plant. The Public Staff stated that it has advised Royal Palms to file a general rate case to reflect current operating costs, but that the Public Staff will take the same position opposing a pass-through even if a rate case is filed. No representative of Royal Palms appeared at the Conference.

The Public Staff recommended that the Commission issue an order "denying the request for tariff revision." The Public Staff interprets the October 29 letter as a request by Royal Palms for a pass-through and, based upon its own "findings," the Public Staff concludes that such a pass-through would be unlawful. The Commission believes that the Public Staff has mis-interpreted the October 29 letter.

The Commission frequently considers and allows during Staff Conferences uncontested letter requests for tariff revisions to pass through increased purchased water and sewer service expenses. See, e.g., Docket Nos. W-1096, Sub 3; W-1116, Sub 6; and seven others decided at the March 24, 2008 Staff Conference and Docket No. W-1237, Sub 3 decided at the March 10, 2008 Staff Conference. Royal Palms's October 29 letter is different from these requests. There is no request for a tariff revision in the October 29 letter, and it does not constitute an application for rate relief. The letter makes certain allegations and then asks three questions. The letter essentially asks for legal advice as to how the utility should proceed, and the Commission cannot provide such advice.[1] Further, the letter is not uncontested: the allegations of the letter present an issue of back-billing as to which the Public Staff opposes relief.[2] Finally, the letter cannot

[1] Royal Palms may retain an attorney to advise it, or the Public Staff may, if it chooses, give procedural guidance to Royal Palms. The Public Staff sometimes gives such procedural guidance to public utilities, especially small utilities with limited resources, and it is proper for the Public Staff to do so. The Public Staff may choose to give such advice to Royal Palms in response to the present letter, but, if it does so, Royal Palms should realize that the Public Staff represents the using and consuming public and that the Public Staff cannot bind or speak for the Commission as to any advice it may give.

[2] Thus, even if the Commission were to relax its procedures and indulge the filing as a request for rate relief, the Commission could not decide the merits of the Public Staff's argument that a pass-through in these circumstances would be unlawful ratemaking. The Staff Conference proceedings herein do not provide the kind of evidentiary record necessary for the Commission to make findings of fact and draw conclusions of law as to the Public Staff's argument. A decision as to such a retroactive or prospective ratemaking argument would require a stipulation of relevant facts or, typically, an evidentiary hearing.

appropriately be treated as a request for a declaratory ruling from the Commission. See Order on Affiliate Contracts issued on August 20, 2003, in Docket No. E-7, Sub 728.[1]

The Commission concludes that there is no request for rate relief pending in this docket and that there is no occasion for a ruling by the Commission other than the Public Staff's recommendation at Staff Conference. That recommendation is denied. The Commission will, however, hold this docket open for 30 days to see if additional filings or an application is made herein.

IT IS, THEREFORE, ORDERED that the recommendation of the Public Staff is hereby denied and that this docket shall be closed after 30 days if no further filings are made herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of April, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Kc041008.03

DOCKET NO. W-1274, SUB 0
DOCKET NO. W-1274, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-1274, SUB 0 In the Matter of Application by Southeastern Jurisdictional Administrative Council, d/b/a/ Lake Junaluska Assembly, Post Office Box 339, Lake Junaluska, North Carolina 28745, for a Certificate of Public Convenience and Necessity to Provide Water and Sewer Utility Service in Lake Junaluska Assembly in Haywood County, North Carolina, and Approval of Rates DOCKET NO. W-1274, SUB 2 In the Matter of Application by Southeastern Jurisdictional Administrative Council, d/b/a/ Lake Junaluska Assembly, for Authority to Amend its Tariff for Providing Water and Sewer Utility Service in Lake Junaluska Assembly in Haywood County, North Carolina	ORDER AMENDING PRIOR FRANCHISE ORDER, APPROVING TARIFF REVISION, AND REQUIRING CUSTOMER NOTICE

[1] "[A] declaratory ruling should not be used as a substitute for another proceeding required by statute. Anticipatory rulings are not favored, and the Commission does not believe that it is appropriate to issue a declaratory ruling as to how the Commission will rule in a future proceeding. If the declaratory ruling requested herein actually commits the Commission, it would render the future statutory proceeding pointless; if the ruling does not commit the Commission, it fails to give [the applicant] the assurance that it says it needs."

BY THE COMMISSION: On May 15, 2008, in Docket No. W-1274, Sub 2, Southeastern Jurisdictional Administrative Council, d/b/a Lake Junaluska Assembly (Lake Junaluska Assembly), filed a letter seeking authority to amend its tariff to pass through to its customers in the Lake Junaluska Assembly service area in Haywood County, North Carolina, the increased cost of purchasing bulk water, bulk wastewater treatment, and fire protection from the Town of Waynesville (Waynesville). Waynesville's new rates will take effect July 1, 2008.

On June 13, 2008, in Docket Nos. W-1274, Sub 0 and Sub 2, the Public Staff filed a Motion to Amend Order and Approve Pass-Through (Motion). This Motion was filed pursuant to G.S. 62-80, requesting and recommending that the Commission amend its Order Approving Franchise and Requiring Customer Notice in Docket No. W-1274, Sub 0, dated December 19, 2007 (Franchise Order), and that the Commission approve the pass-through of the water, wastewater, and fire protection rate increases to Lake Junaluska Assembly from Waynesville.

In its Motion, the Public Staff stated that the Commission's Franchise Order approved the Public Staff's then recommended rates, but those rates were based upon a misapprehension of the facts relating to Lake Junaluska Assembly's unaccounted for water, and the significant differential between Lake Junaluska Assembly's water and wastewater commodity revenues and the purchased bulk water and bulk wastewater expense. As a result, neither the revenue requirement nor the Commission approved rates included any expense for the unaccounted for bulk water or bulk wastewater.

The Public Staff attached to its Motion two letters from Lake Junaluska Assembly dated April 23, 2008 (Exhibit 1 to the Motion), and May 5, 2008 (Exhibit 2 to the Motion), which outlined the unaccounted for water and wastewater, the resulting revenue shortfalls, a description of the aged water distribution system, and the fact that Lake Junaluska Assembly only became aware of the magnitude of the unaccounted for water and wastewater in April 2008.

On the basis of the Motion, including the Lake Junaluska Assembly documentation in Exhibits 1 and 2, the pass-through application filed on May 15, 2008, and the records of the Commission, the Commission makes the following

FINDINGS OF FACT

1. On June 11, 2007 in Docket No. W-1274, Sub 0, Lake Junaluska Assembly filed an application seeking to acquire a water and sewer utility franchise for the Lake Junaluska Assembly area in Haywood County, North Carolina, and for approval of rates.

2. The Commission approved the franchise and rates in the Franchise Order, based upon the Public Staff's recommended rates, which were agreed to by Lake Junaluska Assembly.

3. Lake Junaluska Assembly provides metered water service to approximately 803 customers, metered wastewater service to 726 customers, and flat rate wastewater service to 36 customers.

4. On April 23, 2008, the Public Staff Water Division received a letter from Lake Junaluska Assembly citing a three-month revenue shortfall of $19,644 below expenses, with $29,970 collected at Lake Junaluska Assembly's current usage rates compared to $54,510 purchased bulk water and wastewater expense from Waynesville, resulting in a $24,540 three-month shortfall of usage revenues compared to the bulk purchased water and wastewater expense (Motion, Exhibit 1).

5. Lake Junaluska Assembly sent a follow-up letter, received by the Public Staff Water Division on May 5, 2008, citing how Lake Junaluska Assembly had recently become aware of the magnitude of the unaccounted for water (Motion, Exhibit 2). Attached to the letter was a schedule of the bulk water purchased and metered water sold for January 2006 through April 2008. The unaccounted for water for 2006, 2007, and January through April 2008, is summarized as follows:

2006	=	48.0%
2007	=	32.8%
January through April 2008	=	41.0%

6. The information pertaining to the Lake Junaluska Assembly unaccounted for water was not available to or known by the Public Staff at the time it recommended that the Commission approve the franchise and rates in December 2007, nor was the unaccounted for water information known to the Commission when it issued the Franchise Order. Therefore, the Franchise Order was based upon a misapprehension of facts as to Lake Junaluska Assembly's unaccounted for water and the significant differential between the water and wastewater commodity revenues and the purchased bulk water and wastewater expense. As a result, neither the revenue requirement nor the Commission approved rates included any expense for unaccounted for bulk water and bulk wastewater.

7. Waynesville bills Lake Junaluska Assembly each month for bulk water and bulk wastewater treatment, based upon the master meter through which Waynesville delivers potable water to Lake Junaluska Assembly.

8. Due to the extreme age of portions of the Lake Junaluska Assembly water distribution system (some lines are 100 years old and 50% of the lines are more than 50 years old), the various leaks, the extremely high water pressures resulting from the mountain setting, which at the lake elevation may exceed 200 psi, older meters, and the necessary flushing of water and wastewater lines, the Public Staff recommended a 25% unaccounted for water allowance to be built into the revenue requirement and rates.

9. The Public Staff calculated for 2007, Lake Junaluska had unaccounted for water of 33.3%.

10. The Public Staff recommended that Lake Junaluska Assembly be incentivized to continue to reduce its unaccounted for water. The 25% unaccounted for water allowance that the Public Staff recommended versus the 33.3% actual unaccounted for water in 2007 would leave a $29,400 annual revenue shortfall until Lake Junaluska Assembly further reduces its unaccounted for water.

11. The Public Staff recommended that the Commission amend the Docket No. W-1274, Sub 0, Franchise Order, which would be combined with the Docket No. W-1274, Sub 2, pass-through request for bulk water and bulk wastewater of 10%. The resulting new commodity charge rates that the Public Staff recommended are:

Usage charge, per 1,000 gallons	Current Rates	Recommended Rates	Percentage Increase
Water	\$2.04	\$3.10	52.0%
Wastewater	\$2.76	\$4.19	51.8%

The monthly average residential water and wastewater bills under the current and Public Staff recommended rates, based upon 5,000 gallons per month average consumption, are:

Average bill	Current Rates	Recommended Rates
Water	\$16.85	\$22.15
Wastewater	\$20.15	\$27.30
Total	\$37.00	\$49.45

12. The Public Staff also recommended that the Commission require Lake Junaluska Assembly to file quarterly reports on Lake Junaluska Assembly's program to reduce its unaccounted for water including: (a) leak detection and repair; (b) meter testing and replacements, (c) main and service line repairs and replacements, (d) improved flushing techniques, and (e) updated unaccounted for water calculations, for one year.

13. The Public Staff represented that Lake Junaluska Assembly has been advised of the Public Staff's recommended 25% unaccounted for water allowance, the recommended rates, and the recommendation for quarterly reports and has agreed to each of these recommendations, subject to Commission approval.

14. The Public Staff also recommended the Commission approve an increase in Lake Junaluska Assembly's monthly fire protection rates to equal the new rates charged by Waynesville to Lake Junaluska Assembly as follows:

Rate Class (per meter)	Current Rates	Recommended Rates
Residential	\$3.00	\$4.00
Commercial	\$4.80	\$6.40
Mobile Home Parks	\$3.00	\$4.00
Motel, Hotel, and Cottages	\$1.20, per unit	\$1.60, per unit or \$80.00 maximum

CONCLUSIONS

Based upon the foregoing, the Commission concludes that the Franchise Order should be amended pursuant to G.S. 62-80 due to the misapprehension of facts not known to the Public Staff or the Commission at the time of the issuance of the Franchise Order, relating to the unaccounted for water and wastewater and the significant differential between the water and wastewater usage charge revenues, and the bulk purchased water and bulk purchased wastewater expense.

The Commission concludes it is necessary to revise the water and wastewater usage charge rates to provide for the additional bulk purchased water and bulk purchased wastewater resulting from the unaccounted for water and wastewater, at the Public Staff recommended level of 25%.

The Commission further concludes that the Lake Junaluska Assembly's rates should further be revised to include the 10% increase in costs for purchasing bulk water and bulk wastewater treatment and the 33% increase in the fire protection rates from Waynesville.

IT IS, THEREFORE, ORDERED as follows:

1. That the Order Approving Franchise and Requiring Customer Notice dated December 19, 2007, in Docket No. W-1274, Sub 0, is amended pursuant to G.S. 62-80, so that the Schedule of Rates, approved in this order as Appendix A, includes an allowance for unaccounted for water and wastewater.

2. That Southeastern Jurisdictional Administrative Council, d/b/a Lake Junaluska Assembly, is allowed to increase its water usage charge by $1.06 per 1,000 gallons, its sewer usage charge by $1.43 per 1,000 gallons, and its fire protection fees to equal the new fire protection rate charged by Waynesville.

3. That the Schedule of Rates, attached as Appendix A, is approved and deemed to be filed with the Commission pursuant to G.S. 62-138. That the Schedule of Rates shall become effective for service rendered on and after the date of this Order.

4. That a copy of the Notice to Customers of New Rates, Appendix B, shall be included in the next billing to all customers affected by the tariff revision, and Lake Junaluska Assembly shall submit to the Commission the attached Certificate of Service properly signed and notarized, not later than 15 days after the Notice to Customers of New Rates has been delivered to the customers.

5. That Lake Junaluska Assembly shall file with the Commission, for a period of one year, quarterly reports on Lake Junaluska's Assembly's program to reduce its unaccounted for water including leak detection and repair, meter testing and replacements, main and service line repairs and replacements, improved flushing techniques, and updated unaccounted for water calculations. The first report shall be filed by July 31, 2008, for the quarter ending June 30, 2008, and successive quarterly reports shall be filed October 31, 2008 (quarter ending

September 30, 2008), January 31, 2009 (quarter ending December 31, 2008), and April 30, 2009 (quarter ending March 31, 2009).

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of June, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb062308.01

Commissioners Robert V. Owens, Jr., and Sam J. Ervin, IV, did not participate.

APPENDIX A
PAGE 1 OF 2

SCHEDULE OF RATES

for

SOUTHEASTERN JURISDICTIONAL ADMINISTRATIVE COUNCIL

d/b/a

LAKE JUNALUSKA ASSEMBLY

for providing water and sewer service in

LAKE JUNALUSKA ASSEMBLY

Haywood County, North Carolina

Water Utility Service:

Residential metered base charge	$ 6.65
Commercial metered base charge	
¾" meter	$ 6.65
1" meter	$ 16.63
2" meter	$ 53.20
3" meter	$ 99.75
4" meter	$166.25
6" meter	$332.50
Usage charge, per ccf	$ 2.32
Usage charge, per 1,000 gallons	$ 3.10

Sewer Utility Service:

Residential metered base charge	$ 6.35
Commercial metered base charge	
¾" meter	$ 6.35
1" meter	$ 15.88
2" meter	$ 50.80
3" meter	$ 95.25
4" meter	$158.75
6" meter	$317.50

APPENDIX A
PAGE 2 OF 2

Sewer Utility Service: (continued)

Usage charge, per ccf	$ 3.14
Usage charge, per 1,000 gallons	$ 4.19
Flat rate charge	$ 18.92

Fire Protection

Residential	$4.00 per meter
Commercial	$6.40 per meter
Mobile Homes	$4.00 per meter
Motels, Hotels and Cottages	$1.60 per unit or $80.00 maximum

Tap Fee:

Water	$600.00
Sewer	$650.00

Reconnection Charges:

If water service is cut off by utility for good cause	$20.00
If water service cut off by utility at customer's request:	$20.00

Bills Due: On billing date

Bills Past Due: 28 days after billing date

Billing Frequency: Shall be monthly for service in arrears

Finance Charge For Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date

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Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1274, Sub 2, on this the 25th day of June, 2008.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B
PAGE 1 OF 3

DOCKET NO. W-1274, SUB 0
DOCKET NO. W-1274, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of DOCKET NO. W-1274, SUB 0 In the Matter of Application by Southeastern Jurisdictional Administrative Council, d/b/a/ Lake Junaluska Assembly, Post Office Box 339, Lake Junaluska, North Carolina 28745, for a Certificate of Public Convenience and Necessity to Provide Water and Sewer Utility Service in Lake Junaluska Assembly in Haywood County, North Carolina, and Approval of Rates DOCKET NO. W-1274, SUB 2 In the Matter of Application by Southeastern Jurisdictional Administrative Council, d/b/a/ Lake Junaluska Assembly, for Authority to Amend its Tariff for Providing Water and Sewer Utility Service in Lake Junaluska Assembly in Haywood County, North Carolina	NOTICE TO CUSTOMERS OF NEW RATES

BY THE COMMISSION: Notice is given that the North Carolina Utilities Commission has approved increases in rates to be charged by the Southeastern Jurisdictional Administrative Council, d/b/a Lake Junaluska Assembly (Lake Junaluska Assembly), for water service, wastewater service, and fire protection service in its service area in Haywood County, North Carolina. This decision is based upon information provided by Lake Junaluska Assembly as to the age and condition of the water distribution system and the resulting unaccounted for water, the recommendations of the Public Staff-North Carolina Utilities Commission, and the bulk water, bulk wastewater and fire protection increases from the Town of Waynesville, from which Lake Junaluska Assembly purchases these services.

APPENDIX B
PAGE 2 OF 3

The new rates are as follows:

Water Utility Service:

Residential metered base charge	$ 6.65

Commercial metered base charge	
¾" meter	$ 6.65
1" meter	$ 16.63
2" meter	$ 53.20
3" meter	$ 99.75
4" meter	$166.25
6" meter	$332.50
Usage charge, per ccf	$ 2.32
Usage charge, per 1,000 gallons	$ 3.10

Sewer Utility Service:

Residential metered base charge	$ 6.35
Commercial metered base charge	
¾" meter	$ 6.35
1" meter	$ 15.88
2" meter	$ 50.80
3" meter	$ 95.25
4" meter	$158.75
6" meter	$317.50
Usage charge, per ccf	$ 3.14
Usage charge, per 1,000 gallons	$ 4.19
Flat rate charge	$ 18.92

Fire Protection

Residential	$4.00 per meter
Commercial	$6.40 per meter
Mobile Homes	$4.00 per meter
Motels, Hotels and Cottages	$1.60 per unit or $80.00 maximum

APPENDIX B
PAGE 3 OF 3

The Commission has also ordered Lake Junaluska Assembly to file with the Commission quarterly reports on the upgrades, repairs, and replacements to the water distribution system, and the resulting reduction in the unaccounted for water.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of June, 2008.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WATER AND SEWER – TARIFF REVISION FOR PASS-THROUGH

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-1274, Sub 2, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________ 2008.

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-1274, Sub 2.

Witness my hand and notarial seal, this the ______ day of ____________ 2008.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ________________________________
Date

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Electric Supplier - ES-128, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-129, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-130, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-131, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-132, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-133, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-135, SUB 0; Order Approving Agreement Between Electric Suppliers (09/25/2008)

ELECTRIC SUPPLIER - Reassignment of Service Area/Exchange

Electric Supplier - ES-123, SUB 0; Order Assigning Service Territory (04/19/08); Errata Order (04/24/2008)
Electric Supplier - ES-137, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-138, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-139, SUB 0; Order Closing Docket (05/19/2008)
Electric Supplier - ES-143, SUB 0; Order Approv. Agreemt. of Electric Suppliers (02/06/2008)
Electric Supplier - ES-144, SUB 0; Order Approv. Serv. Area Agreemt. of Elect. Suppliers (02/15/2008)
Electric Supplier - ES-145, SUB 0; Order Approv. Agreemt. of Electric Suppliers (03/27/2008)
Electric Supplier - ES-146, SUB 0; Order Approv. Agreemt. of Electric Suppliers (03/27/2008)
Electric Supplier - ES-149, SUB 0 Order Approving Agreement of Suppliers (06/18/2008)
Electric Supplier - ES-150, SUB 0; Order Approving Agreement of Suppliers (06/18/2008)
Electric Supplier - ES-151, SUB 0; Order Approving Agreement of Suppliers (06/18/2008)
Electric Supplier - ES-152, SUB 0; Order Approv. Agreemt. of Electric Suppliers (06/30/2008)

NATURLA GAS

NATURAL GAS - Adjustments of Rates/Charges

Frontier Natural Gas Company, LLC - G-40,
SUB 70; Order Allowing Rate Changes Effective May 1, 2008 (04/30/2008)
SUB 75; Order Allowing Rate Changes Effective June 1, 2008 (05/28/2008)
SUB 77; Order Allowing Rate Changes Effective September 1, 2008 (08/26/2008)
SUB 78; Order Allowing Rate Changes Effective November 1, 2008 (10/28/2008)
SUB 80; Order Allowing Rate Changes Effective January 1, 2009 (12/23/2008)

NATURAL GAS - Adjustments of Rates/Charges *(Continued)*

Piedmont Natural Gas Company, Inc. - G-9,
SUB 521 & SUB 551; Order Approv. Rate Adjust. Effective April 1, 2008 (03/31/2008)
SUB 521; Order Approving Rate Adjustments Effective November 1, 2008 (10/28/2008)
SUB 528; Order Closing Docket (11/05/2008)
SUB 553; Order Allowing Rate Changes Effective June 1, 2008 (05/28/2008)
SUB 555; Order Allowing Rate Changes Effective October 1, 2008 09/30/2008)
SUB 562; Order Allowing Rate Changes Effective January 1, 2009 (12/23/2008)

Public Service Company of N.C. - G-5,
SUB 496; Order Allowing Rate Changes Effective June 1, 2008 (05/28/2008)
SUB 498; Order Allowing Rate Changes Effective July 1, 2008 (06/30/2008)
SUB 500; Order Allowing Rate Changes Effective October 1, 2008 (09/30/2008)
SUB 501; Order Allowing Rate Changes Effective November 1, 2008 (10/28/2008)
SUB 502; Order Allowing Rate Changes Effective January 1, 2009 (12/23/2008)

NATURAL GAS - Complaint

Piedmont Natural Gas Company, Inc. - G-9,
SUB 540; Order Dismissing Complaint (06/16/2008)
SUB 544; Order Dismissing Complaint (03/28/2008)

Public Service Company of N.C. - G-5,
SUB 489; Order Dismissing Complaint and Closing Docket (06/02/2008)
SUB 499; Order Dismissing Complaint and Closing Docket (08/04/2008)

NATURAL GAS - Contracts/Agreements

Greenbridge Developments - G-56, SUB 0; Order Approv. Natural Gas Master Metering Plan (09/11/2008)

Public Service Company of N.C. - G-5, SUB 475; Order Accepting Agreement for Filing and Allowing Utility to Pay Compensation (08/06/2008)

NATURAL GAS - Filings Due per Order or Rule

Public Service Company of N.C. - G-5, SUB 400A; Order Approving Waiver of Code of Conduct Provision (10/15/2008)

NATURAL GAS - Miscellaneous

Cardinal Extension Company, LLC - G-39, SUB 13; Order Granting Waiver (12/15/2008); Errata Order (12/18/2008)

SPECIAL CERTIFICATE/PSP

SPECIAL CERTIFICATE/PSP - Certificate

Special Certificate/PSP – Certificates Issued

Company	Docket No.	Date Issued
FSH Communications, LLC	SC-1798, SUB 0	(05/12/2008)
Liberman; Arthur	SC-1797, SUB 0	(01/24/2008)
Roskind; Hunter G.	SC-1799, SUB 0	(11/18/2008)

SPECIAL CERTIFICATE/PSP - Cancellation of Certificate

Special Certificate/PSP – Certificates Canceled

Company	Docket No.	Date Issued
Apodaca; Thomas M.	SC-1039, SUB 1	(11/19/2008)
Bible Baptist Christian School	SC-580, SUB 1	(04/30/2008)
Blue Ridge Payphones; Mr. & Mrs. David G. Freeman, d/b/a	SC-1595, SUB 1	(08/28/2008)
Brown, Sr.; Duke C.	SC-1793, SUB 1	(07/31/2008)
Chase High School	SC-412, SUB 1	(10/30/2008)
Com-Tech Systems; Com-Tech Resources, Inc.., d/b/a	SC-1611, SUB 1	(07/16/2008)
Cooper; Martha	SC-1238, SUB 1	(07/31/2008)
D.D. & S. Construction	SC-445, SUB 1	(07/31/2008)
Dairy Fresh, Inc.	SC-833, SUB 2	(07/16/2008)
Edwards Communications, Inc.	SC-290, SUB 1	(12/05/2008)
Haven; Ronald	SC-1682, SUB 1	(11/19/2008)
International Payphone Corp.	SC-1688, SUB 2	(07/31/2008)
Kings Mountain High School	SC-583, SUB 2	(07/16/2008)
Lackey; Jerry P.	SC-415, SUB 1	(10/30/2008)
Long; Darold E.	SC-1628, SUB 1	(08/28/2008)
Moen, Incorporated	SC-1547, SUB 1	(11/19/2008)
Moretz, Garrett W.	SC-1742, SUB 1	(10/30/2008)
Phonetel Technologies, Inc.	SC-485, SUB 7	(02/21/2008)
S & W Phones, Inc.	SC-1717, SUB 1	(04/30/2008)
SAVAC, Inc.	SC-1765, SUB 1	(07/31/2008)
Scotland High School	SC-511, SUB 1	(07/31/2008)
Taylor; Douglas M.	SC-813, SUB 2	(08/28/2008)
Telaleasing Enterprises, Inc.	SC-473, SUB 8	(02/21/2008)
Vestal; Jennifer A.	SC-1436, SUB 1	(07/31/2008)

Hamilton's Telephone Service - SC-1000, SUB 14; SC-953, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (03/28/2008)

National Telephone Co., LLC – SC-1000, SUB 14; SC-1662, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/28/2008)

SPECIAL CERTIFICATE/PSP - Cancellation of Certificate *(Continued)*

Ord-Mark Communications - SC-1000, SUB 14; SC-1621, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (06/19/2008)

Pay Tel Hospitality - SC-1000, SUB 14; Order Affirming Previous Commission Order Canceling Certificate (06/19/2008)

SPECIAL CERTIFICATE/PSP - Miscellaneous

JLR Communications, Inc. - SC-1601, SUB 1; Order Reissuing Certificate (03/28/2008)

Telephone Operating Systems Inc. - SC-1353, SUB 2; Order Reissuing Certificate (07/03/2008)

Verizon South, Inc. - SC-1367, SUB 2; Order Issuing Certificate (05/12/2008)

SPECIAL CERTIFICATE/PSP - Name Change

Caltel, Inc. of North Carolina - SC-1170, SUB 3; Order Reissuing Certificate Due to Address Change (03/28/2008)

SMALL POWER PRODUCER

SMALL POWER PRODUCER - Certificate

Coastal Carolina Clean Power - SP-161, SUB 1; Order Approving Application, Issuing Certificate, and Accepting Registration (06/13/2008)

Decision Support LLC - SP-249, SUB 0; Order Closing Docket (01/09/2008)

HOK, LLC - SP-242, SUB 0; Order Closing Docket (01/09/2008)

Iredell Transmission - SP-243, SUB 0; Order Approving Application and Issuing Certificate (02/28/2008)

Nelson and Diana Paul - SP-231, SUB 0; Order Granting Certificate of Public Convenience and Necessity with Conditions (04/24/2008)

Preston G. Curtis - SP-198, SUB 0; Order Approving Transfer of Certificate and Payment of Capacity Credits (01/17/2008)

SMALL POWER PRODUCER - Electric Generation Certificate

Hendrik J. Rodenburg - SP-246, SUB 0; Order Closing Docket (01/09/2008)

SMALL POWER PRODUCER - Miscellaneous

"ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY" - Orders Issued

Company	Docket No.	Date Issued
Barkley-Sexton Energy, LLC	SP-332, SUB 0	(11/25/2008)
Carolina Solar Energy LLLC	SP-159, SUB 2	(09/26/2008)
Cliffside Mills, LLC	SP-147, SUB 1	(10/31/2008)
FLS SOLAR 10, LLC	SP-341, SUB 0	(10/31/2008)
HOK, LLC	SP-242, SUB 1	(10/31/2008)
Hoosier Hydroelectric, Inc.	SP-311, SUB 0	(07/25/2008)
Iredell Transmission, LLC	SP-243, SUB 1	(12/01/2008)

"ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY" - Orders Issued *(Continued)*

Company	Docket No.	Date Issued
Mayo Hydropower, LLC	SP-137, SUB 2	(09/26/2008)
Mayo Hydropower, LLC	SP-137, SUB 3	(09/26/2008)
MegaWatt Solar, Inc.	SP-211, SUB 1	(09/26/2008)
Orbit Energy, Inc.	SP-297, SUB 0	(06/19/2008)
Pickens Mill Hydro, LLC	SP-148, SUB 1	(10/31/2008)
SAS Institute, Inc.	SP-328, SUB 0	(09/26/2008)
Spray Cotton Mills	SP-107, SUB 1	(09/26/2008)
The Hamlin Family, LLC	SP-294, SUB 0	(10/31/2008)
Wilson Community College	SP-350, SUB 0	(10/31/2008)

TELECOMMUNICATIONS

TELECOMMUNICATIONS - Certificate

Certificates Issued – Local

Company	Docket No.	Date
AGL Networks, LLC	P-1452, SUB 1	(05/23/2008)
Brydels Communications, d/b/a AMIGOS	P-1434, SUB 0	(05/12/2008)
Dabney/Strawn, d/b/a CYBERTEL	P-1457, SUB 1	(07/16/2008)
Fidelity Communication Service III, Inc.	P-1448, SUB 0	(03/28/2008)
Global Capacity Group, Inc.	P-1466, SUB 1	(10/30/2008)
iNETWORKS Group, Inc.	P-1450, SUB 0	(07/03/2008)
New Horizons Comm., d/b/a NHC Comm.	P-1400, SUB 1	(06/18/2008)
Norlight Telecommunications, Inc.	P-1455, SUB 0	(09/18/2008)
Peerless Network of North Carolina	P-1459, SUB 1	(09/18/2008)
Preferred Long Distance, Inc.	P-1453, SUB 1	(06/18/2008)
Swiftel, LLC	P-1439, SUB 0	(09/18/2008)
The New Telephone Company, Inc.	P-1451, SUB 1	(05/12/2008)
Velocity.Net Communications, Inc.	P-1447, SUB 0	(01/25/2008)

Certificates Issued – Long Distance

Company	Docket No.	Date
AGL Networks, LLC	P-1452, SUB 0	(04/30/2008)
ALLIANCE GLOBAL NETWORKS	P-1470, SUB 0	(12/05/2008)
Bandwidth.com CLEC, LLC	P-1432, SUB 1	(02/21/2008)
Central Telecom Long Distance, Inc.	P-1467, SUB 0	(10/15/2008)
Dabney/Strawn, LLC	P-1457, SUB 0	(05/23/2008)
Fidelity Communication Services III	P-1448, SUB 1	(04/30/2008)
Get Connected Texas LLC	P-1449, SUB 0	(04/30/2008)
Global Capacity Group, Inc.	P-1466, SUB 0	(08/27/2008)

Certificates Issued – Long Distance *(Continued)*

Company	Docket No.	Date
iBasis Retail, Inc.	P-1463, SUB 0	(08/27/2008)
iNETWORKS Group, Inc.	P-1450, SUB 1	(12/05/2008)
Intelletrace, Inc.	P-1471, SUB 1	(12/23/2008)
NexUSTel, LLC	P-1456, SUB 0	(05/23/2008)
Norlight Telecommunications, Inc.	P-1455, SUB 1	(10/15/2008)
Peerless Network of North Carolina, LLC	P-1459, SUB 0	(07/16/2008)
Preferred Long Distance, Inc.	P-1453, SUB 0	(05/23/2008)
Sage Spectrum, LLC	P-1464, SUB 0	(08/27/2008)
The New Telephone Company, Inc.	P-1451, SUB 0	(04/30/2008)
Total Holdings, Inc.	P-1465, SUB 0	(12/23/2008)

Pineville Telephone Company - P-120, SUB 16; Order Eliminating Restriction and Authorizing to Provide Resold IntraLATA Toll Service (06/16/2008)

TELECOMMUNICATIONS - Cancellation of Certificate

Certificates Canceled – Local

Company	Docket No.	Date
AmeriMex Communications Corp.	P-834, SUB 4	(12/04/2008)
Nationsline North Carolina, Inc.	P-1337, SUB 2	(07/16/2008)
OPEX Communications, Inc.	P-791, SUB 2	(12/04/2008)
Reliant Communications, Inc.	P-760, SUB 4	(12/04/2008)
WilTel Local Network, LLC	P-1327, SUB 2	(11/18/2008)

Certificates Canceled – Long Distance

Advanced Tel, Inc.	P-1102, SUB 1	(10/30/2008)
Advanced Telemanagement Group, Inc.	P-1342, SUB 1	(07/30/2008)
Axius Inc., d/b/a Axius Communications	P-1205, SUB 1	(07/30/2008)
CitiComm of North Carolina LLC	P-1421, SUB 1	(10/30/2008)
FONICA, LLC	P-1323, SUB 1	(11/18/2008)
Fonix Telecom, Inc.	P-1365, SUB 4	(12/04/2008)
LicStar Telecom, Inc.	P-914, SUB 8	(12/04/2008)
Prime Time Communications, Inc.	P-780, SUB 1	(12/04/2008)
TLX Communications, Inc.	P-508, SUB 1	(10/30/2008)
Touch 1 Communications, Inc.	P-571, SUB 2	(12/05/2008)
Trinsic Communications, Inc.	P-817, SUB 6	(12/04/2008)

3 Voice Communications – P-100, SUB 99; P-100, SUB 99A; P-1419, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

AmTel Communications – P-100, SUB 99; P-100, SUB 99A; P-1236, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

TELECOMMUNICATIONS - Cancellation of Certificate *(Continued)*

Cat Communications International – P-869, SUB 5; Order Canceling Certificates (07/16/08)
Charter Fiberlink NC - CCVII - P-1300, SUB 2; Order Canceling Certificates (07/03/2008)
CI^2, Inc. – P-100, SUB 99; P-100, SUB 99A; P-881, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Computer Network Technology - P-1285, SUB 3; Order Canceling Certificates (01/24/2008)
ComTech 21 – P-100, SUB 99; P-100, SUB 99A; P-995, SUB 4; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Crystal Clear Connections – P-100, SUB 99; P-100, SUB 99A; P-861, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Esodus Communications – P-100, SUB 99; P-100, SUB 99A; P-1232, SUB 2 Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
ETB Communications – P-100, SUB 99; P-100, SUB 99A; P-1253, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
FairPoint Carrier Services – P-100, SUB 99; P-100, SUB 99A; P-932, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Fonix Telecom, Inc. – P-100, SUB 99; P-100, SUB 99A; P-1365, SUB 3; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
GLOBCOM INCORPORATED – P-100, SUB 99; P-100, SUB 99A; P-1264, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Industry Retail Group - P-1328, SUB 2; Order Canceling Certificates (07/15/2008)
JCM Networking, Inc. – P-100, SUB 99; P-100, SUB 99A; P-1308, SUB 3; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
LecStar Telecom, Inc. – P-100, SUB 99; P-100, SUB 99A; P-914, SUB 7; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Local Line America – P-100, SUB 99; P-100, SUB 99A; P-1149, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Maxtel Wireless Communications – P-100, SUB 99; P-100, SUB 99A; P-1079, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
McLeodUSA Telecommunications Services – P-100, SUB 99; P-100, SUB 99A; P-617, SUB 5; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Network PTS, Inc. - P-1350, SUB 2; Order Canceling Certificates (04/30/2008)
ONETELL, INC. – P-100, SUB 99; P-100, SUB 99A; P-992, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Paramount Communications – P-100, SUB 99; P-100, SUB 99A; P-1026, SUB 3; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Preferred Carrier Services, Inc. – P-100, SUB 99; P-100, SUB 99A; P-544, SUB 8; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Reliance GlobalCom Services – P-100, SUB 99; P-100, SUB 99A; P-1441, SUB 1; Order Reinstating Certificate (09/15/2008)
Simflex Communications – P-100, SUB 99; P-100, SUB 99A; P-1156, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)
Southern Digital Network, d/b/a FDN Communications - P-1314, SUB 4; Order Canceling Certificates (03/28/2008)
Starvox Communications – P-100, SUB 99; P-100, SUB 99A; P-1379, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

TELECOMMUNICATIONS - Cancellation of Certificate *(Continued)*

Symtelco, LLC - P-1311, SUB 2; Order Canceling Certificates (01/24/2008)

Synergy Communications Corp. – P-100, SUB 99; P-100, SUB 99A; P-1332, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Trinsic Communications – P-100, SUB 99; P-100, SUB 99A; P-817, SUB 5; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

United Communications HUB – P-100, SUB 99; P-100, SUB 99A; P-993, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Vantage Telecom, LLC – P-100, SUB 99; P-100, SUB 99A; P-1425, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Vertex Communications – P-100, SUB 99; P-100, SUB 99A; P-1333, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Volo Communications of North Carolina - P-1297, SUB 2; Order Canceling Certificates (04/10/2008)

Vycera Communications – P-100, SUB 99; P-100, SUB 99A; P-1363, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Wholesale Carrier Services – P-100, SUB 99; P-100, SUB 99A; P-1168, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Winsonic Digital Media Group – P-100, SUB 99; P-100, SUB 99A; P-1430, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

Winstar Communications – P-100, SUB 99; P-100, SUB 99A; P-1161, SUB 4; Order Affirming Previous Commission Order Canceling Certificate (08/14/2008)

TELECOMMUNICATIONS - Complaint

BellSouth Telecommunications - P-55,

SUB 1719; Order Dismiss. Complaint and Closing Docket (Robert S. Pilot) (01/24/2008)

SUB 1743; Order Dismiss. Complaint & Closing Docket (Renita Graham) (11/25/2008)

dPi Teleconnect, LLC – P-55, SUB 1577; Order Denying dPi's November 19, 2007 Motion to Reconsider (07/18/2008)

NewSouth Comm. - P-772, SUB 7; Order Closing Docket (Complaint of BellSouth Telecomm.) (12/08/2008)

NuVox Comm. - P-913, SUB 7; Order Vacating Order and Closing Docket (12/08/2008)

NuVox Comm. - P-1341, SUB 1; Order Dismiss. Claims & Closing Docket (BellSouth Telecommunications) (11/07/2008)

TELECOMMUNICATIONS - Contracts/Agreements

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) – Orders Issued

BellSouth Telecommunications, Inc -- P-55,

SUB 1397 (Cellco Partnership, d/b/a Verizon Wireless) (02/29/2008)

SUB 1418 (American Fiber Systems, Inc.) (02/29/2008)

SUB 1437 (XO Communications Services, Inc.) (02/29/2008)

SUB 1452 (Business Telecom, Inc.) (09/17/2008); ((12/10/2008)

SUB 1487 (Norlight, Inc.) (07/10/2008); (08/08/2008)

<u>ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s)</u> –**Orders Issued** *(Cont.)*
BellSouth Telecommunications, Inc -- P-55, *(Continued)*

SUB 1521 (Level 3 Communications, LLC) (07/10/2008)
SUB 1526 (T-Mobile USA, Inc.) (07/10/2008)
SUB 1533 (Access Integrated Networks, Inc.) (07/10/2008)
SUB 1574 (Covista, Inc.) (12/10/2008)
SUB 1585 (Electronics Service Company of Hamlet, LLC) (12/10/2008)
SUB 1588 (BellSouth Long Distance, Inc.) (07/10/2008)
SUB 1598 (Progress Telecom, LLC) (07/10/2008)
SUB 1601 (Lightyear Network Solutions, LLC) (07/10/2008)
SUB 1613 (Advent Paging) (12/10/2008)
SUB 1618 (NOW Communications, Inc.) (07/10/2008)
SUB 1620 (IDS Telecom Corporation) (07/10/2008)
SUB 1626 (DSLnet Communications, LLC) (07/10/2008)
SUB 1628 (TelCove Operations, Inc.) (05/15/2008); ((07/10/2008); (09/17/2008)
SUB 1631 (AT&T Communications of the Southern States) (07/10/2008)
SUB 1634 (TCG of the Carolinas, Inc.) (07/10/2008)
SUB 1637 (Dialog Telecommunications, Inc.) (07/10/2008)
SUB 1653 (US LEC Communications, Inc.) (07/10/2008)
SUB 1656 (GSC Telecommunications, Inc.) (02/29/2008)
SUB 1657 (CommPartners, LLC) (08/08/2008)
SUB 1706 (South Carolina Net, d/b/a Sprint Telecom) (07/10/2008)
SUB 1721 (DIECA Comm., d/b/a Covad Comm. Co.) (02/29/2008); (12/10/2008)
SUB 1726 (Time Warner Telecom of North Carolina) (02/29/2008); (10/21/2008)
SUB 1727 (School Link, Inc.) (02/29/2008)
SUB 1728 (Global Connection, Inc. of America) (02/29/2008)
SUB 1729 (Syniverse Technologies, Inc.) (02/29/2008)
SUB 1730 (WinSonic digital Media Group, Ltd.) (02/29/2008)
SUB 1735 (Neutral Tandem-North Carolina) (03/27/2008)
SUB 1736 (Vista PCS, LLC) (03/27/2008)
SUB 1737 (National Network Communications, Inc.) (03/27/2008)
SUB 1738 (LTS of Rocky Mount, LLC) (03/27/2008)
SUB 1740 (Broadplex, LLC) (05/15/2008)
SUB 1741 (N.C. RSA 3 Cellular Tele. Co., d/b/a Carolina West Wireless (05/15/2008)
SUB 1742 (Connect Communications, LLC) (05/15/2008)
SUB 1745 (Universal Telecom, Inc.) (07/10/2008)
SUB 1746 (SkyBest Communications, Inc.) (08/08/2008)
SUB 1747 (Bandwidth.com CLEC, LLC) (07/10/2008)
SUB 1748 (SCANA Communications, Inc.) (08/08/2008)
SUB 1749 (Access Integrated Networks & Birch Telecom of the South) (08/08/2008)
SUB 1753 (Strata8 Networks, Inc.) (09/17/2008)
SUB 1754 (Qwest Communications Corporation) (10/21/2008)
SUB 1755 (Balsam West FiberNET, LLC) (10/29/2008)
SUB 1757 (Affordable Phone Services) (12/10/2008)
SUB 1758 (Budget Prepay, Inc.) (12/10/2008)

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) –Orders Issued *(Cont.)*

Carolina Telephone and Telegraph Company& Central Telephone Company - P-7,
SUB 1176; P-10, SUB 799 (Ernest Communications, Inc.) (02/29/2008)
SUB 1177; P-10, SUB 800 (American Fiber Network, Inc.) (02/29/2008)
SUB 1178; P-10, SUB 801 (School Link, Inc.) (05/15/2008)
SUB 1180; P-10, SUB 803 (Global Connection, Inc. of North Carolina) (05/15/2008)
SUB 1182; P-10, SUB 804 (DeltaCom, Inc.) (07/10/2008)
SUB 1183; P-10, SUB 805 (Business Telecom, Inc., d/b/a BTI) (07/10/2008)
SUB 1184; P-10, SUB 806 (Bandwidth.com CLEC, LLC (05/15/2008)
SUB 1185; P-10, SUB 807 (Momentum Telecom, Inc.) (05/15/2008)
SUB 1186; P-10, SUB 808 (Access Point, Inc.) (05/15/2008)
SUB 1191; P-10, SUB 811 (LTS of Rocky Mount, LLC) (09/17/2008)
SUB 1192; P-10, SUB 812 (SCANA Communications, Inc.) (09/17/2008)
SUB 1193; P-10, SUB 813 (Dabney/Strawn, LLC, d/b/a Cybertel) (09/17/2008)
SUB 1194; P-10, SUB 814 (South Carolina Net, d/b/a Sprint Telecom) (12/10/2008)
SUB 1197; P-10, SUB 817 (MCImetro Access Transmission Services) (12/10/2008)
SUB 1198; P-10, SUB 818 (Kentucky Data Link, Inc.) (12/10/2008)

MCImetro Access Transmission Serv. – P-474, SUB 14 (BellSouth Telecomm.) (10/29/2008)

North State Telephone Company - P-42, SUB 158 (North Carolina Telcom, LLC) (03/27/2008)

NuVox Communications, Inc. P-913, SUB 5 (BellSouth Telecommunications) (02/29/2008)

Verizon South, Inc. – P-19,
SUB 346 (Madison River Communications, LLC) (09/17/2008)
SUB 464 (Metropolitan Telecommunications of North Carolina, Inc.) (02/29/2008)
SUB 520 (Wholesale Carrier Services, Inc.) (03/27/2008)
SUB 521 (Bandwidth.com CLEC, LLC) (05/15/2008)
SUB 523 (Fidelity Communication Services III, Inc.) (07/08/2008)
SUB 524 (PNG Telecommunications, Inc.) (08/08/2008)

Windstream Concord Telephone, Inc. P-16,
SUB 231 (North Carolina Telcom, LLC) (03/27/2008)
SUB 232; P-118, SUB 161 (ALLTEL & New Cingular Wireless PCS) (10/21/2008)
SUB 233; P-118, SUB 133 (ALLTEL & ALLTEL Communications) (10/29/2008)

Windstream North Carolina, LLC. - P-118,
SUB 159 (North Carolina Telcom, LLC) (03/27/2008)
SUB 162 (OneTone Telecom, Inc.) (12/10/2008)

BellSouth Telecommunications - P-55, SUB 1532; Order Allowing Extension of Agreement (11/03/2008)

Charter Fiberlink NC – CCO - P-1299, SUB 4; SUB 5; SUB 6; Order Dismissing Approval Requests and Closing Dockets (08/22/2008)

Nextel South Corp. – P-55, SUB 1710; Order Allowing Adoption of Sprint ICA (09/02/2008)

Sprint Communications Company L.P. - P-294, SUB 34; Order Terminating Exemption and Approving Adoption of Agreement (12/17/2008)

TELECOMMUNICATIONS - Discontinuance

BellSouth Telecommunications - P-55,
SUB 1732; Order Authorizing Disconnection Subject to Conditions (01/18/2008); Order Closing Docket (08/15/2008)
SUB 1733; Order Authorizing Disconnection Subject to Conditions (01/18/2008); Order Closing Docket (08/15/2008)
Carolina Telephone and Telegraph & Central Telephone – P-7, SUB 1187; P-10, SUB 809; Order Author. Terminat. Subject to Conditions (06/20/2008)
Progress Telecom LLC – P-1175, SUB 2; Order Granting Petition (10/30/2008)
Shentel Converged Services -- P-1422, SUB 2; Order Designating TWC Digital Phone LLC as Universal Service Provider for the Villas (10/31/2008)

TELECOMMUNICATIONS - Miscellaneous

BellSouth Telecommunications, Inc. - P-55,
SUB 1013; Order Approv. AT&T's Modif. Price Regulat. Plan (05/19/2008); Order Grant. AT&T's Req. to Discont. Offering its Internet Call Waiting Service (12/12/2008)
SUB 1549; Order Closing Docket (01/18/2008)
SUB 1685; P-1308, SUB 2; Order Authoriz. Termin. Subject to Conditions (02/13/2008); Order Closing Dockets (08/15/2008)
SUB 1705; Order Closing Docket (08/15/2008)
SUB 1731; Order Granting Numbering Resources (01/16/2008)
SUB 1734; Order Granting Numbering Resources (01/25/2008)
SUB 1750; Order Granting Numbering Resources (07/08/2008)
SUB 1751; Order Granting Numbering Resources (08/05/2008)
SUB 1756; Order Granting Numbering Resources (09/19/2008)
SUB 1762; Order Granting Numbering Resources (12/15/2008)
Broadview Networks - P-1184, SUB 2; P-972, SUB 3; P-1105, SUB 3; Order Allowing Limited Waiver of Rule R20-1 (07/09/2008)
Broadwing Communications - P-1257, SUB 2; P-1316, SUB 2; Order Approving Waiver of Rule R20-1 (10/09/2008)
Carolina Telephone and Telegraph Company - P-7,
SUB 1181; Order Granting Numbering Resources (03/11/2008)
SUB 1188; Order Granting Numbering Resources (06/06/2008)
SUB 1190; Order Granting Numbering Resources (07/15/2008)
Springboard Telecom - P-758, SUB 3; Order Granting Numbering Resources (05/21/2008)
Sprint Communications Co. L.P. - P-294,
SUB 30; Recommended Arbitration Order (08/29/2008)
SUB 33; Order Granting Numbering Resources (05/14/2008)
Time Warner Cable Information Services (N.C.) - P-1262, SUB 2; Order Approving Composite Agreement (01/31/2008)

TELECOMMUNICATIONS - Miscellaneous *(Continued)*

Verizon South, Inc. P-19,

SUB 522; Order Closing Docket (04/17/2008)

SUB 525; Order Authorizing Disconnection Subject to Conditions (07/25/2008)

TELECOMMUNICATIONS - Reinstating Certificate

American Fiber Network, Inc. – P-100, SUB 99; P-100, SUB 99A; P-937, SUB 3; Order Reinstating American Fiber Network Certificate (10/14/2008)

Bandwidth.com – P-100, SUB 99; P-100, SUB 99A; P-1432, SUB 2; Order Reinstating Certificate (08/26/2008)

Cebridge Telecom NC – P-100, SUB 99; P-100, SUB 99A; P-1360, SUB 2; Order Reinstating Certificate (09/08/2008)

Computer Central of Wilson – P-100, SUB 99; P-100, SUB 99A; P-1381, SUB 1; Order Reinstating Certificate (08/29/2008)

EveryCall Communications - P-100, SUB 99; P-100, SUB 99A; P-1278, SUB 2; Order Reinstating Certificate (09/02/2008)

FRC, LLC – P-100, SUB 99; P-100, SUB 99A; P-1345, SUB 1; Order Reinstating Certificate (08/18/2008)

INFOTELECOM, LLC – P-100, SUB 99; P-100, SUB 99A; P-1375, SUB 2; Order Reinstating Certificate (09/02/2008)

IPC Network Services – P-100, SUB 99; P-100, SUB 99A; P-1383, SUB 2; Order Reinstating Certificate (09/18/2008)

Metrostat Communications – P-100, SUB 99; P-100, SUB 99A; P-1212, SUB 2; Order Reinstating Certificate (09/02/2008)

Midwestern Telecommunications Inc. – P-100, SUB 99; P-100, SUB 99A; P-1215, SUB 2; Order Reinstating Certificate (10/06/2008)

Network Innovations, Inc. – P-100, SUB 99; P-100, SUB 99A; P-1427, SUB 1; Order Reinstating Certificate (09/02/2008)

OneTone Telecom, Inc. – P-100, SUB 99; P-100, SUB 99A; P-1159, SUB 2; Order Reinstating Certificate (09/29/2008)

TDPC, Inc. – P-100, SUB 99; P-100, SUB 99A; P-872, SUB 2; Order Reinstating Certificate (09/11/2008)

Universal Telecom, Inc. – P-100, SUB 99; P-100, SUB 99A; P-873, SUB 2; Order Reinstating Certificate (09/02/2008)

TELECOMMUNICATIONS - Rule Adoption/Revision

Reduced Rate Long Distance - P-1103, SUB 2; P-1160, SUB 1; Order Allowing Waiver of Rule R20-1 and Providing for Cancellation of Horizon Certificate (02/26/2008)

TELECOMMUNICATIONS - Sale/Transfer

BellSouth Telecomm. - P-55, SUB 1725; P-638, SUB 5; Order Closing Dockets (08/15/2008)

Citizens Telephone Co. - P-12, SUB 109; Order Approving Transfer of Control (11/13/2008)

Navigator Telecommunications - P-850, SUB 3; P-886, SUB 3; Order Approving Transfer and Granting Waiver of Rule R20-1 (10/09/2008)

Windstream Communications - P-1394, SUB 1; P-621, SUB 7; P-118, SUB 158; P-295, SUB 14; Order Allowing Migration of Customers (01/22/2008)

ORDERS AND DECISIONS LISTED

TRANSPORTATION

TRANSPORTATION - Adjustments of Rates/Charges

Rates-Truck - T-825, SUB 342; Order Approving Fuel Surcharge (03/04/2008); (03/18/2008); (04/01/2008); (04/29/2008); (05/27/2008); (06/10/2008); (08/12/2008); (08/19/2008); (08/26/2008); (09/09/2008); (10/14/2008); (10/21/2008); (10/28/2008); (11/04/2008); (11/10/2008); (11/25/2008); (12/02/2008); (12/16/2008); (12/23/2008)

TRANSPORTATION - Common Carrier Certificate

"ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION" – Orders Issued

Company	Docket No.	Date
Appalachian Moving & Storage Co.	T-4383, SUB 0	(02/18/2008)
B's Moving	T-4401, SUB 0	(08/04/2008)
Ballantyne & Beyond	T-4400, SUB 0	(05/09/2008)
Discover Moving & Storage, Inc.	T-4387, SUB 0	(01/24/2008)
Exodus Works	T-4385, SUB 0	(01/16/2008)
Kelly Moving, Inc.	T-4391, SUB 0	(06/04/2008)
Lake Norman Moving Services, LLC	T-4397, SUB 0	(05/02/2008)
Lake Norman Moving & Storage, LLC	T-4388, SUB 0	(03/05/2008)
Langlois Ventures, d/b/a VIP Logistics	T-4394, SUB 0	(07/07/2008)
Maddox Moving Services	T-4384, SUB 0	(01/24/2008)
Reliable Moving Company, LLC	T-4398, SUB 0	(05/05/2008)
Shore to Shore Moving & Storage	T-4137, SUB 4	(02/20/2008)
Southpark Moving Consultants	T-4402, SUB 0	(07/22/2008)
Suddath Relocation Systems of Charlotte	T-4392, SUB 0	(03/18/2008)
The Express Movers	T-4404, SUB 0	(08/19/2008)
The Moving Company, Inc.	T-4408, SUB 0	(10/27/2008)
Tri-City Movers	T-4407, SUB 0	(10/21/2008)
Two Men and a Truck of Charleston	T-4390, SUB 0	(02/15/2008)
West Furniture, Inc.	T-4373, SUB 0	(09/19/2008)

TRANSPORTATION - Certificate

Murray Transfer & Storage Co., d/b/a Atlantic Moving Systems - T-4389, SUB 0; Order Grant. Application for Certificate of Exemption (03/14/2008); Errata Order (03/24/2008)

Jeff's Express - T-4403, SUB 0; Order Grant. Application for Certificate of Exemption (09/18/2008)

Sam A. Byers & Sons Moving Service - T-4030, SUB 5; Order Granting Application for Certificate of Exemption (08/01/2008)

Sawyer Enterprises of Pensacola - T-4395, SUB 0; Order Granting Application for Certificate of Exemption (06/05/2008)

Turner's Moving - T-4405, SUB 0; Order Grant. Applicat. for Certif. of Exempt. (09/17/2008)

ORDERS AND DECISIONS LISTED

TRANSPORTATION - Cancellation of Certificate

"ORDER CANCELING CERTIFICATE OF EXEMPTION" – Orders Issued

Company	Docket No.	Date
All American Movers of Goldsboro, Inc.	T-1934, SUB 5	(09/09/2008)
Beach Movers	T-4277, SUB 1	(12/23/2008)
Beltmann Group Inc.	T-4130, SUB 1	(05/27/2008)
Charlotte Metro Moving & Storage	T-4147, SUB 1	(02/05/2008)
CMTR Moving Services	T-4355, SUB 1	(10/15/2008)
Five Star Moving Co.	T-4328, SUB 1	(03/05/2008)
John W. Woodlief Moving & Services	T-4326, SUB 2	(03/13/2008)
Meticulous Movers, Inc.	T-4307, SUB 1	(07/08/2008)
Outer Banks Movers	T-4306, SUB 2	(09/05/2008)
Standard Moving & Storage, Inc.	T-492, SUB 10	(09/09/2008)
Tar Heel Moving & Storage	T-4295, SUB 1	(05/27/2008)
US-1 Van Lines of North Carolina	T-4163, SUB 2	(03/28/2008)

A Better Choice Movers - T-100, SUB 71; T-4260, SUB 2; Order Canceling Show Cause Hearing and Canceling Certificate of Exemption (01/28/2008)

The Move Makers, Inc. - T-4179, SUB 2; Order Affirm. Prev. Comm. Order Cancel. Certificate (02/19/2008); Order Rescinding Order Canceling Certificate of Exemption (02/21/2008)

TRANSPORTATION - Name Change

AAA Moving, Inc. - T-4126, SUB 4; Order Approving Name Change (02/21/2008)
Ace Movers - T-4324, SUB 1; Order Approving Name Change (10/09/2008)
Blue Ridge Movers, Inc. - T-4359, SUB 1; Order Approving Name Change (07/11/2008)
MBM Moving Systems, LLC - T-4396, SUB 1; Order Approving Name Change (07/11/2008)
Moving Men - T-4236, SUB 2; Order Approving Name Change (03/10/2008)
Murphy Movers, Inc. - T-4351, SUB 1; Order Approving Name Change (02/15/2008)

TRANSPORTATION – Rate Increase

Hilldrup Moving & Storage - T-825, SUB 343; Order Requesting Study Canceling Certificate of Exemption (05/27/2008)

TRANSPORTATION - Show Cause

A Few Good Men Moving - T-4361, SUB 1; Recommended Order Canceling Certificate of Exemption (05/27/2008)

Carolina Moving Systems - T-4319, SUB 1 Recommended Order Canceling Certificate of Exemption (05/27/2008)

Discover Moving & Storage - T-4387, SUB 1; Recommended Order Canceling Certificate of Exemption (10/30/2008)

Lake Norman Moving & Storage - T-4388, SUB 1; Recommended Order Canceling Certificate of Exemption (08/08/2008)

TRANSPORTATION - Show Cause *(Continued)*

Southpark Moving Consultants - T-4402, SUB 1; Recommended Order Canceling Certificate of Exemption (10/30/2008)

West's Durham Transfer & Storage - T-1865, SUB 5; Recommended Order Canceling Certificate of Exemption (10/28/2008)

TRANSPORTATION - Suspension

Affordable Movers - T-4350, SUB 1; Order Granting Authorized Suspension (11/12/2008)
ASE Moving Services - T-3245, SUB 5; Order Granting Authorized Suspension (03/05/2008)
Campbell's Transfer & Storage - T-2471, SUB 8; Order Grant. Author. Suspen. (12/08/2008)
Doma Moving and Storage - T-4366, SUB 2; Order Granting Author. Suspension (11/18/2008)
Helpful Movers - T-4269, SUB 4; Order Granting Authorized Suspension (06/09/2008)
Lake Norman Moving Services - T-4397, SUB 1; Order Rescind. Order Granting Authorized Suspension (11/26/2008)
M.M. Smith Storage Warehouse - T-916, SUB 6; Order Grant. Author. Suspen. (06/06/2008)
Moody Movers - T-4246, SUB 1; Order Granting Authorized Suspension (12/08/2008)
Morehead Moving & Storage - T-918, SUB 10; Order Grant. Author. Suspension (06/27/2008)
Quality Moving & Storage - T-4225, SUB 1; Order Grant. Authorized Suspension (05/14/2008)
RD Helms Transfer Co. - T-4224, SUB 3; Order Granting Authorized Suspension (04/25/2008)
Southpark Moving Consultants - T-4402, SUB 2; Order Grant. Author. Suspens. (11/14/2008)
Stanley's Transfer Co. - T-1913, SUB 11; Order Granting Authorized Suspension (06/27/2008)
Triad Moving, Inc. - T-4337, SUB 1; Order Granting Authorized Suspension (12/23/2008)

TRANSPORTATION - Sale/Transfer

Central Moving & Storage – T-4185, SUB 1; T-4386, SUB 0; Order Approving Transfer and Name Change (01/04/2008)

MBM Moving Systems – T-2882, SUB 2; T-4396, SUB 0; Order Approving Transfer and Name Change (05/02/2008)

WATER AND SEWER

WATER AND SEWER - Bonding

Hawk Run Development of Asheville - W-1238, SUB 4; Recommended Order Assessing Penalties (11/18/2008)

Sugarloaf Utility - W-1154, SUB 5; Order Approving Bond and Surety and Releasing Bond and Surety (07/14/2008)

Total Environmental Solutions - W-1146, SUB 7; Order Approving Bond and Surety and Releasing Bond and Surety (12/17/2008)

WATER AND SEWER – Certificate

Aqua North Carolina - W-218, SUB 240 & SUB 263; Order Approv. Tariff Amendment (03/25/2008)

Cashiers Water Works - W-1271, SUB 0; Recommended Order Granting Certificate of Public Convenience and Necessity and Approving Rates (06/03/2008)

WATER AND SEWER – Certificate *(Continued)*

Flat Creek Utilities - W-1272, SUB 0; Order Granting Franchise, Approving Rates, Imposing Moratorium, and Requiring Reports and Notice (01/28/2008)

JPC Utilities, LLC - W-1263, SUB 0; Order Granting Franchise, Approving Stipulation and Regulatory Conditions, Approving Rates (05/30/2008); Errata Order (06/10/2008)

Lowery Services - W-1180, SUB 0; Order Allow. Withdrawal and Closing Docket (06/06/2008)

Old North Utility Services - W-1279, SUB 0; Order on Petition for Declaratory Ruling and Application for Certificate of Public Convenience (03/18/2008)

Saxapahaw Utility Co. - W-1250, SUB 1; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (09/19/2008)

"ORDER GRANTING FRANCHISE AND APPROVING RATES" – Orders Issued

Company	Docket No.	Date
Aqua North Carolina (Grande Villas)	W-218, SUB 253	(12/23/2008)
Aqua North Carolina (Collybrooke Subdiv.)	W-218, SUB 265	(02/08/2008)
Aqua North Carolina (Ferguson Creek Village)	W-218, SUB 270	(09/03/2008)
Heater Utilities (The Parks at Meadowview)	W-274, SUB 583	(06/10/2008)
Heater Utilities (Silver Creek Subdiv.)	W-274, SUB 658	(06/03/2008)
Heater Utilities (Honeycutt Landing Subdiv.)	W-274, SUB 667	(03/14/2008)
Heater Utilities (Keenland Manor Subdiv.)	W-274, SUB 669	(03/14/2008)
Heater Utilities (Hoke Landing Subdiv.)	W-274, SUB 670	(03/14/2008)
Heater Utilities (Neighbor's Walk Subdiv.)	W-274, SUB 674	(06/03/2008)
Heater Utilities (Inwood of Yates Branch Subdiv.)	W-274, SUB 681	(06/04/2008)
Heater Utilities (Chasewateer Subdiv.)	W-274, SUB 691	(10/13/2008)
Heater Utilities (The Oaks at Hunter Hills)	W-274, SUB 692	(10/14/2008)

WATER AND SEWER - Cancellation of Certificate

Asheville Property Management - W-1145, SUB 15; Order Canceling Franchise (10/21/2008)

Gullzar Properties, LLC - W-1266, SUB 1; Order Canceling Franchise and Requiring Customer Notice (08/05/2008)

SND Properties, LLC - W-1267, SUB 1; Order Canceling Franchise (06/04/2008)

White Forest Wastewater Treatment - W-1157, SUB 1; Order Canceling Franchise and Closing Docket (06/05/2008)

Winkler, Carl K. - W-1206, SUB 7; Order Canceling Franchise (11/18/2008)

WATER AND SEWER - Complaint

Aqua North Carolina - W-218,
SUB 269; Order Dismissing Complaint and Closing Docket (Angela Dixon) (06/20/2008)
SUB 271; Order Dismissing Complaint and Closing Docket (Rafael Osuba) (07/11/2008)

Transylvania Utilities - W-1012, SUB 9; Order Canceling Hearing, Dismissing Complaint and Closing Docket (Carroll Leach) (07/22/2008)

<u>WATER AND SEWER - Discontinuance</u>

Community Investments, LLC - W-1158,
SUB 5; Order Canceling Franchise (Lone Pine Mobile Home Park) (11/04/2008)
SUB 6; Order Canceling Franchise (Cross Creek Pond Mobile Home Park) (11/04/2008)

H & H Development - W-315, SUB 3; Order Cancel. Franchise (Hedgefield Sub.) (01/15/2008)

Western Utilities - W-229, SUB 7; Order Cancel. Franchises and Releasing Bond (Western Hills Subdiv.) (08/01/2008)

Yadkin Water Corp. - W-585, SUB 5; Order Authorizing Discontinuance (Country View Estates) (07/15/2008)

<u>WATER AND SEWER – Emergency Operator</u>

Environmental Maintenance Systems, Inc. - W-1054, SUB 11; Order Appointing Emergency Operator and Requiring Customer Notice (01/28/2008)

<u>WATER AND SEWER – Rate Increase</u>

Aqua North Carolina, Inc. – W-218, SUB 251; Order Granting Partial Rate Increase and Requiring Customer Notice (01/29/2008)

Enviracon Utilities, Inc. - W-1236, SUB 2; Order Increasing Claim Settlement Fund and Requiring Meeting (04/10/2008)

<u>WATER AND SEWER - Sale/Transfer</u>

Centerline Utilities of Eastern N.C. - W-1222, SUB 1; W-811, SUB 9; Order Approving Transfer, Discharg. Emerg. Operator, Cancel. Franchise, and Requir. Notice (09/02/2008)

Heater Utilities - W-274, SUB 685; Order Approving Transfer and Requiring Customer Notice (07/15/2008)

M Realty, LLC - W-1281, SUB 0; W-1011, SUB 13; Order Grant. Transfer of Franchise, Approv. Rates, and Requir. Customer Notice (09/12/2008); Order Releasing Bond and Surety (10/14/2008)

Porters Neck Co. - W-1059, SUB 6; Order Approv. Transf. and Cancel. Franchise (06/05/2008)

Viking Utilities Corp. - W-740, SUB 7; Order Approv. Transfer, Cancel. Franchise, and Requiring Customer Notice (04/11/2008)

Village Water and Tobacco Branch Village - W-504, SUB 8; Order Approving Transfer, Canceling Franchise, and Discharging Emergency Operator (07/30/2008)

<u>WATER AND SEWER - Securities</u>

Old North Utility Services - W-1279, SUB 1; Order Granting Authority to Issue and Sell Securities and Allowing Payments Under Affiliate Agreement (06/18/2008)

<u>WATER AND SEWER - Tariff</u>

Emerald Plantation Utilities - W-1211, SUB 2; Order Approving Tariff Revision (03/13/2008)

WATER AND SEWER - Tariff Revision for Pass-Through

"ORDER APPROVING TARIFF REVISION" – Orders Issued

Company	Docket No.	Date
Asheville Property Management	W-1145, SUB 12	(03/26/2008)
Asheville Property Management	W-1145, SUB 13	(03/26/2008)
Carolina Water Service of N.C.	W-354, SUB 315	(08/05/2008)
Crestview, LLC	W-1096, SUB 3	(03/26/2008)
Duckett, Gordon & Susan	W-1237, SUB 3	(03/11/2008)
Indian Creek Mobile Home Park	W-1116, SUB 6	(03/26/2008)
JACTAW Properties, LLC	W-1209, SUB 4	(03/26/2008)
Laurel Wood Utilities, Inc.	W-1155, SUB 5	(03/26/2008)
Mayfaire 1, LLC	W-1249, SUB 1	(04/18/2008)
Meco Utilities Inc.	W-1166, SUB 5	(10/30/2008)
Pine Valley Mobile Home Park	W-1131, SUB 6	(03/26/2008)
Rumfelt; Mark & Luther; Fred	W-1254, SUB 1	(03/26/2008)
Total Environmental Solutions, Inc.	W-1146, SUB 8	(12/23/2008)
Town & Country Mobile Home Park	W-1193, SUB 4	(03/26/2008)
TRG Charlotte, LLC	W-1257, SUB 1	(12/17/2008)

Carolina Water Service of N. C. - W-354, SUB 293; Order Ending Reporting Requirement and Closing Docket (01/11/2008)

Christmount Christian Assembly - W-1079, SUB 8; Order Approving Tariff Revision and Requiring Customer Notice (08/01/2008)

Joyceton Water Works - W-4, SUB 12; Order Approving Tariff Revision and Requiring Customer Notice (06/03/2008)

Lake Junaluska Assembly - W-1274, SUB 1; Order Approving Tariff Revision and Requiring Customer Notice (02/25/2008)

WATER AND SEWER - Contiguous Water Extension

"ORDER RECOGNIZING CONTIGUOUS EXTENSION AND APPROVING RATES" – Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc.		
(Beau Rivage Market Place Shop. Cntr.)	W-218, SUBS 257 & 165	(02/08/2008)
(Fleetwood Falls Subdivision)	W-218, SUB 264	(02/08/2008)
(Bakersfield Subdivision)	W-218, SUB 266	(09/03/2008)
(Westfield Village Subdivision)	W-218, SUB 268	(09/03/2008)
Carolina Water Service of North Carolina		
(Eagles Crossing Subdivision)	W-354, SUB 287	(03/03/2008)

"ORDER RECOGNIZING CONTIGUOUS EXTENSION AND APPROVING RATES" -- Orders Issued *(Continued)*

Company	Docket No.	Date
CWS Systems, Inc.		
(Fairfield Sapphire Vista Subdiv.)	W-778, SUB 58	(02/18/2008)
(Laurel Mountain Estates)	W-778, SUB 59	(02/18/2008)
Fairways Utilities, Inc.		
(Watermark Landing Subdivision)	W-787, SUB 34	(01/28/2008)
Heater Utilities, Inc.		
(Estates at Laurel Ridge Subdiv.)	W-274, SUB 597	(06/10/2008)
(The Bluffs Subdivision)	W-274, SUB 598	(06/10/2008)
(The McBane Subdivision)	W-274, SUB 608	(06/10/2008)
(Flowers Plantation Comm. Develop.)	W-274, SUB 609	(02/11/2008)
(Wilder's Woods Subdivision)	W-274, SUB 627	(02/11/2008)
(The Parks at Meadowview Subdiv.)	W-274, SUB 637	(06/10/2008)
(The Parks at Meadoeview Subdiv.)	W-274, SUB 646	(07/21/2008)
(Hasentree Subdivision)	W-274, SUB 648	(07/02/2008)
(Heritage Point Estates Subdiv.)	W-274, SUB 659	(06/03/2008)
(Hasentree Subdivision)	W-274, SUB 660	(06/03/2008)
(Knoxhaven Subdivision)	W-274, SUB 663	(02/11/2008)
(Pineville Club Subdivision)	W-274, SUB 664	(06/03/2008)
(Kelsey at Falls Lake Subdiv.)	W-274, SUB 668	(02/11/2008)
(Honeycutt Landing Subdivision)	W-274, SUB 671	(03/27/2008)
(Rocky Ridge Farms Subdivision)	W-274, SUB 672	(03/27/2008)
(Seville Subdivision)	W-274, SUB 675	(03/27/2008)
(Dayton Woods Subdivision)	W-274, SUB 682	(06/04/2008)
(Lassiter Farm Subdivision)	W-274, SUB 683	(06/04/2008)
(Hasentree Subdivision)	W-274, SUB 684	(10/28/2008)
(High Grove Subdivision)	W-274, SUB 688	(10/13/2008)
(Beckenham Subdivisio)	W-274, SUB 689	(10/13/2008)
(The Preserves at Long Branch Farms)	W-274, SUB 690	(10/13/2008)

Fairways Utilities, Inc. - W-787, SUB 19; Reissued Order Recognizing Contiguous Extension and Approving Rates (Windswept Subdivision) (01/11/2008)

Heater Utilities, Inc. - W-274,
SUB 664; Errata Order (06/09/2008)
SUB 684; Errata Order (10/31/2008)
SUB 864; Errata Order (10/30/2008)

KDHWWTP, L.L.C. - W-1160,
SUB 7; Order Recognizing Contiguous Extension (07/17/2008)
SUB 8; Order Recognizing Contiguous Extension (11/05/2008)

WATER AND SEWER - Merger

Aqua North Carolina - W-218, SUB 273; W-787, SUB 38; W-1032, SUB 11; W-274, SUB 687; W-989, SUB 11; W-899, SUB 39; W-981, SUB 13; Order Approving Merger (12/05/2008)

WATER AND SEWER - Rate Increase

A & D Water Service, Inc. - W-1049, SUB 11; Order Closing Docket (07/16/2008)

Aqua North Carolina - W-218, SUB 251; Order Granting Partial Rate Increase and Requiring Customer Notice (01/29/2008)

Blue Creek Utilities - W-857, SUB 6; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice (12/11/2008)

Carolina Trace Utilities - W-1013, SUB 7; Order Granting Partial Rate Increase and Requiring Customer Notice (12/19/2008)

Chatham Utilities - W-1240, SUB 3; Order Canceling Hearing, Granting Rate Increase, and Requiring Customer Notice (11/07/2008)

Crosby Utilities - W-992, SUB 6; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice (06/06/2008)

Enviro-Tech of North Carolina - W-1165, SUB 3; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice (05/13/2008)

Honeycutt; Wayne M. - W-472, SUB 14; Order Granting Partial Rate Increase and Requiring Customer Notice (03/03/2008)

Scientific Water and Sewerage - W-176, SUBS 32 & 29; Order Recogniz. Contiguous Extension., Approv. Rates, Accept. Bond, Requir. Conf. and Closing Docket (04/24/2008)

ST Utility Co. - W-984, SUB 2; Recomm. Order Grant. Partial Rate Increase and Requir. Customer Notice (12/22/2008); Order Allow. Recomm. Order to Become Effective and Final (12/22/2008)

Water Quality Utilities - W-1264, SUB 1; Order Allow. Withdrawal of Application (11/17/2008)

WATER AND SEWER - Declaratory Ruling

Environmental Maintenance Systems - W-1054, SUB 11; Recommend. Order Approv. Surcharge and Assessment for Improve. and Requir. Customer Notice (06/03/2008)

WATER AND SEWER - Filings Due per Order or Rule

Carolina Water Service, Inc. of North Carolina - W-354, SUB 236; Order Accepting Executed Effluent Easement and Irrigation Agreement (08/14/2008)

RESALE OF WATER AND SEWER

RESALE OF WATER AND SEWER - Certificate

"ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES" -- Orders Issued

Company	Docket No.	Date
Addison Point, LLC	WR-748, SUB 0	(04/16/2008)
Alaris Village Apartments, LLC	WR-894, SUB 0	(12/04/2008)
Alliance PP2 FX2, LP		
(Autumn Ridge Apartments)	WR-786, SUB 0	(05/14/2008)
(Windsor Harbor Apts.)	WR-786, SUB 1	(06/04/2008)
AMFP 1 Hamilton Ridge, LLC	WR-805, SUB 0	(06/17/2008)
ARCML06 LLC	WR-532, SUB 1	(12/09/2008)
Ardrey Kell Townhomes, LLC	WR-891, SUB 0	(12/04/2008)
Arnold and Deborah Tolson	WR-872, SUB 0	(10/31/2008)
Ashley Court Apartments, LLC	WR-781, SUB 0	(04/22/2008)
Ashton Village Limited Partnership	WR-802, SUB 0	(06/11/2008)
Athena Misty Woods, LLC	WR-848, SUB 0	(09/18/2008)
Atkins Circle II, LLC	WR-747, SUB 0	(04/09/2008)
Auston Woods Charlotte-Phase II	WR-721, SUB 0	(02/12/2008)
Banks;'Parks	WR-849, SUB 0	(09/24/2008)
Battleground Oaks Greensboro	WR-792, SUB 0	(05/14/2008)
BC Development II, LLC	WR-873, SUB 0	(10/30/2008)
Beachwood Associates, LLC	WR-880, SUB 0	(11/14/2008)
Beaver Creek Section I Associates	WR-881, SUB 0	(11/13/2008)
Beaver Creek Sections II Associates	WR-878, SUB 0	(11/13/2008)
Berelli & Associates Commercial Holdings	WR-828, SUB 0	(07/30/2008)
Blue Ridge Developers, Inc.		
(Drake Street Mobile Home Park)	WR-822, SUB 0	(07/23/2008)
(Dixie Trail Mobile Home Park)	WR-822, SUB 1	(07/23/2008)
Bouwfonds North Pointe, LP	WR-895, SUB 0	(12/09/2008)
BRC Goldsboro, LLC	WR-845, SUB 0	(09/16/2008)
BRC Independence Park, LLC	WR-790, SUB 0	(07/22/2008)
BRC Twin Oaks, LLC	WR-844, SUB 0	(09/16/2008)
BRC Whites Mill, LLC	WR-830, SUB 0	(08/06/2008)
Bromley Park, LLC	WR-665, SUB 0	(01/03/2008)
Brookberry Park Apartments, LLC	WR-798, SUB 0	(06/04/2008)
CAJF Associates, L.L.C	WR-833, SUB 0	(08/07/2008)
Camden Summit Partnership, L.P.	WR-6, SUB 124	(01/03/2008)
Carrboro II, LLC	WR-788, SUB 0	(05/09/2008)
Carrington Apt. Properties, LLC	WR-860, SUB 0	(10/08/2008)
Cary Towne Park, LLC	WR-874, SUB 0	(12/30/2008)
CCSF, LLC	WR-836, SUB 0	(07/24/2008)
Cedar Trace, LLC	WR-897, SUB 0	(12/17/2008)

"ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES'
Orders Issued *(Continued)*

Company	Docket No.	Date
Chamberlain Place Apts., LLC	WR-819, SUB 0	(07/18/2008
Colonial Realty Ltd.	WR-437, SUB 8	(09/25/2008
Community Investments, LLC		
(Lone Pine Mobile Home Park)	WR-877, SUB 0	(11/05/2008
(Cross Creek Pond MHP)	WR-877, SUB 1	(11/05/2008
Courtney Estates Grand, LLC	WR-729, SUB 0	(03/25/2008
CP Lakeside, LLC	WR-847, SUB 0	(09/22/2008
Crosland Arboretum, LLC	WR-859, SUB 0	(10/08/2008
Crosland Wilson Park, LLC	WR-885, SUB 0	(11/14/2008
Crown Ridge Partners, LLC	WR-818, SUB 0	(07/17/2008
DGN Land Management, LLC	WR-757, SUB 0	(04/29/2008
Donathan/Briarleigh Park Properties, LLC	WR-797, SUB 0	(06/04/2008
DRA Woodland Park LP	WR-861, SUB 0	(10/09/2008
Dry Ridge Properties, LLC	WR-867, SUB 0	(10/22/2008
Durham Mews Section II Associates	WR-884, SUB 0	(11/17/2008
Durham Section I Associates, LLC	WR-883, SUB 0	(11/17/2008
ELPF Station Nine, LLC	WR-724, SUB 0	(02/27/2008
Emmett Ramsey	WR-796, SUB 0	(06/04/2008
Ethan Pointe, LLC	WR-744, SUB 0	(04/09/2008
Fairfield BCMR Centerview	WR-829, SUB 0	(08/05/2008
Fairfield Radbourne Lake	WR-743, SUB 0	(04/02/2008
Farrington Lake Apartments	WR-827, SUB 0	(07/28/2008
Formax Properties		
(L & W. Mobile Home Park)	WR-899, SUB 0	(12/08/2008
(Mobile Acres II MHP)	WR-899, SUB 1	(12/08/2008
Fortune Bay Associates	WR-785, SUB 0	(05/07/2008
Fuller Street Development	WR-726, SUB 0	(02/29/2008
Fund II Meadows, LLC	WR-846, SUB 0	(09/18/2008
GMH/GF Varsity Lake Associates	WR-869, SUB 0	(10/23/2008
Grace Park Development, LLC	WR-893, SUB 0	(12/22/2008
GS Hamptons, LLC	WR-732, SUB 0	(03/19/2008
Hampton Ridge Partners	WR-901, SUB 0	(12/22/2008
Harris Pointe, LLC	WR-756, SUB 0	(04/22/2008
Henson Place, LLC	WR-755, SUB 0	(04/22/2008
Hillsborough Seminole, LLC	WR-787, SUB 0	(05/09/2008
JBA Investments, LLC	WR-898, SUB 0	(12/17/2008
KUWA, LLC	WR-843, SUB 0	(09/17/2008
Lees Chapel Partners, LLC		
(Chapel Walk Apartments)	WR-875, SUB 0	(10/30/2008
(Cross Creek Apartments)	WR-875, SUB 1	(10/30/2008
Lofts SREF at Lakeview, Inc.	WR-780, SUB 0	(04/29/2008
Long Creek Club Apartments	WR-866, SUB 0	(10/16/2008

"ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES" -- Orders Issued *(Continued)*

Company	Docket No.	Date
Longview Apartments, LLC	WR-825, SUB 0	(07/25/2008)
Mid-America Apartments, Ltd.	WR-22, SUB 21	(04/09/2008)
Mill Creek Apartments, LLC	WR-856, SUB 0	(10/07/2008)
Mission Matthews Place LeaseCo.	WR-858, SUB 0	(10/07/2008)
Mission Millbrook LeasCo. LLC	WR-857, SUB 0	(10/07/2008)
Morganton Place Apartments, LLC	WR-782, SUB 0	(04/29/2008)
Morrisville Associates, LLC	WR-879, SUB 0	(11/17/2008)
Moss; Allen H.		
(Maple Terrace MHP)	WR-896, SUB 0	(12/09/2008)
(Crestview II MHP)	WR-896, SUB 1	(12/09/2008)
MP Creekwood, LLC	WR-738, SUB 0	(04/03/2008)
MP Cross Creek, LLC	WR-736, SUB 0	(03/18/2008)
MP Hunt Club, LLC	WR-735, SUB 0	(03/18/2008)
MP The Oaks, LLC	WR-734, SUB 0	(03/18/2008)
MP The Pointe, LLC	WR-733, SUB 0	(04/03/2008)
MP The Regency LLC	WR-740, SUB 0	(04/03/2008)
MP Winterwood, LLC	WR-739, SUB 0	(03/18/2008)
MRWR, L.L.C.	WR-832, SUB 0	(08/07/2008)
NationsProperties, LLC	WR-821, SUB 0	(07/23/2008)
North Carolina Carrboro Ltd.	WR-789, SUB 0	(05/09/2008)
Northcross Marquis, L.P.	WR-864, SUB 0	(10/16/2008)
Northwestern Mutual Life Ins. Co.	WR-129, SUB 8; WR-369, SUB 4	(11/25/2008)
Northwoods Mews Associates	WR-882, SUB 0	(11/17/2008)
Oak Park at Briar Creek, LLC	WR-807, SUB 0	(06/20/2008)
Oglesby Properties, LLC	WR-838, SUB 0	(08/26/2008)
Old Salem Apartment Associates	WR-783, SUB 0	(05/07/2008)
Palmer Apartments Realty, LLC	WR-720, SUB 0	(02/04/2008)
Panther Creek Apartments, LLC	WR-820, SUB 0	(07/18/2008)
Paradise North Carolina, LLC	WR-888, SUB 0	(11/21/2008)
Pleasant Garden Apartments, LLC	WR-742, SUB 0	(03/19/2008)
POAA, L.L.C.	WR-834, SUB 0	(08/07/2008)
Providence Park Properties, LLC	WR-840, SUB 0	(08/27/2008)
Providence Point Apartments, LLC	WR-715, SUB 0	(04/03/2008)
Prudential Insurance Co. of America	WR-38, SUB 4	(01/29/2008)
REBA Reafield, LLC et al.	WR-793, SUB 0	(05/30/2008)
Red Chief, LLC	WR-722, SUB 0	(03/12/2008)
Rehobeth Point, LLC	WR-730, SUB 0	(03/13/2008)
Ridgeview MHP, LLC	WR-712, SUB 0	(01/29/2008)
Riverwalk Apts. of Lincoln County	WR-870, SUB 0	(10/24/2008)
RWJF Associates, L.L.C.	WR-835, SUB 0	(08/07/2008)

"ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES" - Orders Issued *(Continued)*

Company	Docket No.	Date
Schrader; Michael	WR-795, SUB 0	(06/09/2008)
S. E. Portfolio Apartments, LLC	WR-505, SUB 5	(10/29/2008)
Shadowood Apartments, LLC	WR-903, SUB 0	(12/30/2008)
Sherwood Place, LLC	WR-723, SUB 0	(02/12/2008)
Silverstone Apartments, LLC	WR-902, SUB 0	(12/30/2008)
Simpson Promenade Park, LLC	WR-876, SUB 0	(10/31/2008)
South and Bland, LLC	WR-889, SUB 0	(11/21/2008)
Sovereign Development Company	WR-784, SUB 0	(05/07/2008)
Spinksville III, and Ambiance Parkside	WR-727, SUB 0	(03/05/2008)
Summerwood Apartments, LLC	WR-855, SUB 0	(12/15/2008)
Suncoast Cornerstone, et al.	WR-801, SUB 0	(07/14/2008)
Suncoast North Park, LLC	WR-808, SUB 0	(06/24/2008)
Tau Valley, LLC	WR-823, SUB 0	(07/23/2008)
The Apartments at Crossroads, LLC	WR-851, SUB 0	(10/06/2008)
Town Square West, LLC	WR-862, SUB 0	(10/09/2008)
Treybrooke, LLC	WR-824, SUB 0	(07/23/2008)
VAC L.L.L.P.		
(Booker Creek Apartments)	WR-831, SUB 0	(08/08/2008)
(Chapel Tower Apartments)	WR-831, SUB 1	(08/08/2008)
(Colonial Townhouse Apartments)	WR-831, SUB 2	(08/08/2008)
(Duke Manor Park Apartments)	WR-831, SUB 3	(08/08/2008)
(Franklin Woods Apartments)	WR-831, SUB 4	(08/08/2008)
(Holly Hills Apartments)	WR-831, SUB 5	(08/08/2008)
(Kingswood Apartments)	WR-831, SUB 6	(08/08/2008)
(Knollwood Apartments)	WR-831, SUB 7	(08/08/2008)
(Pinegate Apartments)	WR-831, SUB 8	(08/08/2008)
Verde Apartments, LP	WR-806, SUB 0	(06/17/2008)
Village at Cliffdale Apartments	WR-842, SUB 0	(09/05/2008)
Village Creek West Properties	WR-713, SUB 0	(01/29/2008)
West Market Partners, LLC	WR-749, SUB 0	(04/16/2008)
Westdale NC Summit Creek Ltd.	WR-826, SUB 0	(07/28/2008)
Westdale Pepertree, Ltd.	WR-815, SUB 0	(07/15/2008)
Westdale Poplar Place, LLC	WR-816, SUB 0	(07/15/2008)
Westfield Funding, LLC	WR-753, SUB 0	(04/18/2008)
WF Elizabeth, LLC	WR-868, SUB 0	(10/22/2008)
Windsor Landing Investments I, et al.	WR-886, SUB 0	(11/14/2008)
Winkler; Carl K.	WR-887, SUB 0	(11/18/2008)
WMCi Raleigh IV, LLC	WR-803, SUB 0	(06/11/2008)
Woodberry Asheville Apartments, LLC	WR-791, SUB 0	(05/14/2008)
Woodfield Glen, LLC	WR-800, SUB 0	(06/11/2008)
WW Partnership	WR-850, SUB 0	(09/24/2008)

RESALE OF WATER AND SEWER – Certificate *(Continued)*

Alliance PP2 FX2, LP - WR-786, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates (06/27/2008)
CSHV Belmont, LLC - WR-752, SUB 0; WR-370, SUB 1; Order Granting Certificate of Authority and Approving Rates and Canceling Certificate of Authority (04/18/2008)
Dry Ridge Properties, LLC - WR-867, SUB 0; Errata Order (10/23/2008)
Lofts SREF at Lakeview, Inc. - WR-780, SUB 0; Errata Order (04/29/2008)
MP Winterwood, LLC - WR-739, SUB 0; Errata Order (03/19/2008)
Sovereign Development Company - WR-784, SUB 0; Errata Order (06/09/2008)
Steelecroft Farm, LLC - WR-688, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates (06/27/2008)
Westdale Poplar Place, LLC - WR-816, SUB 0; Errata Order (07/16/2008)

RESALE OF WATER AND SEWER - Cancellation of Certificate

"ORDER CANCELING CERTIFICATE OF AUTHORITY" -- Orders Issued

Company	Docket No.	Date
Battleground Oaks Limited	WR-191, SUB 3	(05/14/2008)
Bedford Properties	WR-294, SUB 1	(12/09/2008)
Benj. E. Sherman & Sons	WR-161, SUB 5	(02/05/2008)
Brentmoor Apartments, LLC	WR-224, SUB 1	(12/02/2008)
Brier Creek Partners, LLC	WR-290, SUB 1	(02/11/2008)
Brown Investment Properties		
(The Marchester Apartments)	WR-46, SUB 14	(01/08/2008)
(Palmer House Apts.)	WR-46, SUB 15	(01/08/2008)
Camden Summit Partnership, L.P.		
(Summit Hill Apartments)	WR-6, SUB 135	(07/28/2008)
(Summit Creek Apartments)	WR-6, SUB 136	(07/28/2008)
CASA Group, LLC	WR-307, SUB 3	(11/26/2008)
City View Associates, LLC	WR-346, SUB 1	(09/04/2008)
CMS/Promenade Park, LP	WR-265, SUB 1	(10/30/2008)
Crown Ridge Acquisition Co.	WR-403, SUB 2	(04/10/2008)
Davidson Income Real Estate, L.P.	WR-339, SUB 2	(06/17/2008)
EQR - Fankey 2004 Limited Partnership	WR-681, SUB 2	(12/22/2008)
Fairfield Cornerstone, LLC	WR-469, SUB 2	(04/22/2008)
Fairfield North Park, LP	WR-551, SUB 2	(04/22/2008)
Fifth and Poplar Associates, LLC	WR-193, SUB 1	(01/03/2008)
Fortress Highlands, LLC	WR-347, SUB 2	(09/23/2008)
MLQ-MLL, LLC	WR-623, SUB 1	(10/07/2008)
Northstone Apartments, LLC	WR-458, SUB 1	(08/19/2008)
Parkside Village Associates	WR-150, SUB 4	(03/05/2008)
Petit Five, LLC	WR-127, SUB 6	(01/15/2008)
Transwestern Reserve at Waterford, L.L.C.	WR-406, SUB 1	(12/17/2008)
Transwestern Woodway Point, LLC	WR-424, SUB 4	(04/03/2008)

"ORDER CANCELING CERTIFICATE OF AUTHORITY" -- Orders Issued *(Cont.)*

Company	Docket No.	Date
UDR of NC, Limited Partnership		
(Morganton Place Apartments)	WR-3, SUB 158	(03/24/2008)
(Village at Cliffdale Apts.)	WR-3, SUB 159	(03/24/2008)
(Woodberry Apartments)	WR-3, SUB 160	(03/25/2008)
(Dominion Peppertree Apts.)	WR-3, SUB 183	(04/17/2008)
(Stoney Pointe Apartments)	WR-3, SUB 184	(04/30/2008)
(Dominion Crown Point Apts.)	WR-3, SUB 185	(07/08/2008)
(Forest Hills Apartments)	WR-3, SUB 186	(07/15/2008)
USA Courtney Creek LeaseCo, LLC	WR-642, SUB 1	(08/12/2008)
USA Parkside 1, LLC	WR-381, SUB 2	(01/31/2008)
Varsity Lane Associates, LLC	WR-484, SUB 2	(06/04/2008)
West Bloomfield Commons, L.L.C	WR-331, SUB 2	(06/26/2008)
Westfield Funding, LLC	WR-753, SUB 2	(10/31/2008)
Windridge Oxford Associates	WR-149, SUB 5	(05/14/2008)
Woodland Park Apartment Property, LLC	WR-361, SUB 1	(09/02/2008)

Benj. E. Sherman & Sons, Inc. - WR-161, SUB 5; Errata Order (02/06/2008)
Fifth and Poplar Associates, LLC - WR-193, SUB 1; Errata Order (01/04/2008)

RESALE OF WATER AND SEWER - Reinstating Certificate
Hudson Landings Ltd. - WR-84, SUB 3; Order Canceling Certificate of Authority (01/28/2008)

RESALE OF WATER AND SEWER - Sale/Transfer

"ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES" -- Orders Issued

Arboretum at Weston Holdings -- WR-809, SUB 0; WR-259, SUB 1 (07/02/2008)
BMA Bellemeade Apartments, LLC -- WR-814, SUB 0; WR-248, SUB 1 (07/15/2008)
BMA Eden Apartments, LLC -- WR-728, SUB 0; WR-247, SUB 1 (03/06/2008)
BMA Heatherwood Kensington Apts. -- WR-708, SUB 0; WR-202, SUB 2 (01/24/2008)
BMA Huntersville Apartments, LLC -- WR-811, SUB 0; WR-203, SUB 2 (07/10/2008)
BMA Lakewood, LLC -- WR-817, SUB 0; WR-256, SUB 2 (07/17/2008)
BMA Monroe III Apartments, LLC -- WR-812, SUB 0; WR-240, SUB 2 (07/10/2008)
BMA North Sharon Amity, LLC -- WR-810, SUB 0; WR-244, SUB 1 (07/10/2008)
BMA Wexford Apartments, LLC -- WR-813, SUB 0; WR-242, SUB 2 (07/10/2008)
Campus-Raleigh, LLC -- WR-745, SUB 0; WR-115, SUB 3 (04/09/2008)
CH Realty IV/Notting Hill, LLC -- WR-852, SUB 0; WR-68, SUB 4 (10/07/2008)
CND Bridgeport, LLC -- WR-751, SUB 0; WR-674, SUB 1 (04/17/2008)
CND Duraleigh Woods, LLC -- WR-741, SUB 0; WR-680, SUB 4 (03/19/2008)
CND Sailboat Bay, LLC -- WR-737, SUB 0; WR-680, SUB 3 (03/19/2008)
CND Sommerset Place, LLC -- WR-746, SUB 0; WR-680, SUB 5 (04/09/2008)
CORE Hunters Chase H, LLC, et al. -- WR-837, SUB 0; WR-348, SUB 3 (08/19/2008)

"ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES" -- Orders Issued *(Continued)*

Deerwood Apartments, LLC -- WR-853, SUB 0; WR-494, SUB 1 (10/08/2008)
DRA Cypress Pointe, LP -- WR-863, SUB 0; WR-359, SUB 1SUB 1 (10/10/2008)
DRA Lodge at Millard Creek, LP -- WR-854, SUB 0; WR-58, SUB 5(10/08/2008)
DRA Quad, LP -- WR-871, SUB 0; WR-279, SUB 1 (10/24/2008)
Dutch Village Apartments, LLC -- WR-865, SUB 0; WR-491, SUB 1 (10/16/2008)
G&I VI Brynn Marr, LP -- WR-759, SUB 0; WR-3, SUB 162 (04/23/2008)
G& I VI Cape Harbor Mill, LP -- WR-763, SUB 0; WR-3, SUB 166 (07/31/2008)
G&I VI Clear Run, LP -- WR-762, SUB 0; WR-3, SUB 164 (04/23/2008)
G& I VI Colony Village, LP -- WR-779, SUB 0; WR-3, SUB 182 (05/01/2008)
G&I VI Cooper Mill, LP -- WR-767, SUB 0; WR-3, SUB 170 (07/22/2008)
G&I VI Courtney, LP -- WR-775, SUB 0; WR-3, SUB 178 (04/23/2008)
G&I VI Crossing, LP -- WR-764, SUB 0; WR-3, SUB 167 (04/30/2008)
G&I VI Crosswinds, LP -- WR-772, SUB 0; WR-3, SUB 175 (04/22/2008)
G&I VI Harris Pond, LP -- WR-771, SUB 0; WR-3, SUB 174 (04/22/2008)
G&I VI Lake Lynn, LP -- WR-761, SUB 0; WR-3, SUB 165 (04/23/2008)
G&I VI Liberty Crossing, LP -- WR-760, SUB 0; WR-3, SUB 163 (04/23/2008)
G&I VI Mallard, LP -- WR-776, SUB 0; WR-3, SUB 179 (05/01/2008)
G&I VI Meadows at Kildaire, LP -- WR-769, SUB 0; WR-3, SUB 172 (04/23/2008)
G&I VI Mill Creek, LP -- WR-774, SUB 0; WR-3, SUB 177 (04/23/2008)
G&I VI Norcroft, LP -- WR-768, SUB 0; WR-3, SUB 171 (04/30/2008)
G&I VI Oaks at Weston, LP -- WR-778, SUB 0; WR-3, SUB 181 (05/01/2008)
G&I VI Providence Court, LP -- WR-758, SUB 0; WR-3, SUB 161 (04/22/2008)
G&I VI Ramsgate, LP -- WR-765, SUB 0; WR-3, SUB 168 (04/30/2008)
G&I VI Sprint Forest, LP -- WR-766, SUB 0; WR-3, SUB 169 (04/23/2008)
G&I VI The Creek, LP -- WR-770,
SUB 0; WR-3, SUB 173 (The Creek Apartments) (04/23/2008)
SUB 1; WR-3, SUB 187 (Sharon Crossing Apts.) (10/10/2008)
G&I VI Trinity Park, LP -- WR-773, SUB 0; WR-3, SUB 176 (05/01/2008)
G&I VI Walnut Creek, LP -- WR-777, SUB 0; WR-3, SUB 180 (04/23/2008)
Hamilton Florida Partners, LLC -- WR-841, SUB 0; WR-556, SUB 1 (09/04/2008)
LVP Eastchase, LLC -- WR-716, SUB 0; WR-42, SUB 52 (01/24/2008)
LVP Glen, LLC -- WR-718, SUB 0; WR-42, SUB 54 (01/24/2008)
LVP Timber Creek, LLC -- WR-717, SUB 0; WR-42, SUB 53 (01/24/2008)
LVP Wendover, LLC -- WR-719, SUB 0; WR-42, SUB 55 (02/12/2008)
Mid-America Apartments, L.P. -- WR-22, SUB 24; WR-574, SUB 2 (10/02/2008)
Mission Durham LeaseCo, LLC -- WR-804,
SUB 0; WR-344, SUB 1 (Mission Univ. Pines Apts.) (09/16/2008)
SUB 1; WR-336, SUB 4 (Mission Triangle Point Apts.) (07/08/2008)
MP Regency Place, LLC -- WR-714, SUB 0; WR-39, SUB 82 (01/15/2008)
RAIA Properties NC-2, LLC -- WR-839, SUB 0; WR-209, SUB 5 (08/26/2008)
RAIA Self-Storage Montville, et al. -- WR-890, SUB 0; WR-654, SUB 1 (11/25/2008)
Spring Ridge Apartments, LLC -- WR-725, SUB 0; WR-472, SUB 1 (04/09/2008)
TMP Lodge at Crossroads, LLC -- WR-799, SUB 0; WR-129, SUB 7 (06/05/2008)

"ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY AND APPROVING RATES" -- Orders Issued *(Continued)*

Tryon Village Acquisition Co. -- WR-750, SUB 0; WR-576, SUB 2 (04/17/2008)
Wakefield Glen Apartments, LLC -- WR-892, SUB 0; WR-83, SUB 7 (12/04/2008)
Waterford Lakes Partners, LLC -- WR-731, SUB 0; WR-423, SUB 3 (03/13/2008)
WMCi Raleigh III, LLC -- WR-754, SUB 0 ; WR-360, SUB 1 (04/18/2008)

LVP GLEN LLC - WR-718, SUB 0; WR-42, SUB 54; Errata Order (01/25/2008)

RESALE OF WATER AND SEWER - Tariff Revision for Pass-Through

"ORDER APPROVING TARIFF REVISION" – Orders Issued

Abbington Place/Charlotte, LLC - WR-621, SUB 2 (05/09/2008)
Abbington Place/Charlotte, LLC WR-453, SUB 3 (05/09/2008)
Abbington SPE, LLC - WR-596, SUB 1 (08/29/2008)
ACG-CRLP Crescent Matthews, LLC - WR-463, SUB 3 (07/01/2008)
Addison Park, LLC - WR-409, SUB 3 (05/06/2008)
Advenir@Monroe 5920, LLC - WR-511, SUB 1 (08/04/2008)
AIMCO Williamsburg Manor, LLC - WR-675,
SUB 1 (Williamsburg Manor Apts.) (09/30/2008)
SUB 2 (Williamsburg Manor Apts.) (10/14/2008)
Alpha Mill, LLC - WR-559, SUB 2 (05/07/2008)
Apartment REIT Residences at Braemar, LLC - WR-655, SUB 1 (10/23/2008)
Arbor Trace Apartments, LLC - WR-222, SUB 2 (08/29/2008)
ARC Communities 11, LLC - WR-534, SUB 1 (08/12/2008)
ARCML06 LLC - WR-532, SUB 2 (12/15/2008)
ARC3NC, LLC - WR-597, SUB 1 (12/15/2008)
Arringdon Development, Inc. - WR-179, SUB 5 (10/20/2008)
Ascot Point Village Apartments, LLC - WR-273, SUB 5 (08/20/2008)
Ashborough Investors, LLC - WR-489, SUB 1 (09/05/2008)
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Auston Grove – Raleigh Apts. L.P. -- WR-233,
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BBR/Allerton, LLC - WR-618, SUB 2 (03/05/2008)

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BBR/Chapel Hill, LLC - WR-607,
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BBR/Marina Waterfront, LLC - WR-605, SUB 2 (05/19/2008)
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BEL-EQR IV Limited Partnership - WR-679,
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BES University Tower Fund III, LLC - WR-365, SUB 3 (07/24/2008)
BIR Charlotte I, L.L.C. - WR-477, SUB 1 (10/14/2008)
Birkdale Apartments, LLC - WR-209, SUB 4 (05/07/2008)
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BMA Shelby Apartments, LLC - WR-709, SUB 1 (08/18/2008)
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BNP/Chason Ridge, LLC - WR-64, SUB 7 (10/28/2008)
BNP/Harris Hill, LLC - WR-393, SUB 3 (05/19/2008)
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Burd Properties of Fayetteville, LLC - WR-585,
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DDRTC Birkdale Village LLC - WR-699,
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Forest Durham Apartments, LLC, et al. - WR-616,
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GMC Sun Valley, LLC - WR-456,
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