NINETY-SIXTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2006 THROUGH DECEMBER 31, 2006

NINETY-SIXTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

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January 1, 2006, through December 31, 2006

Jo Anne Sanford, Chair

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

Howard N. Lee, Commissioner

William T. Culpepper, III, Commissioner

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

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

LETTER OF TRANSMITTAL

December 31, 2006

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, 2006, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2006, and ending December 31, 2006.

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

Jo Anne Sanford, Chair

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

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Renne Vance, Chief Clerk

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GENERAL ORDERS -- ELECTRIC

DOCKET NO. E-100, SUB 103

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation of Integrated Resource Planning in North Carolina – 2005	))))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REQUIRING ADDITIONAL INFORMATION IN FUTURE REPORTS

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on May 1, 2006, and June 27 – 28, 2006; Pitt County Courthouse, Greenville, North Carolina, on May 31, 2006; and Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina, on June 1, 2006

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Chair Jo Anne Sanford, and Commissioners Robert V. Owens, Jr., Lorinzo L. Joyner, and William T. Culpepper, III

APPEARANCES:

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

Len S. Anthony, Deputy General Counsel, and Kendal C. Bowman, Associate General Counsel, Progress Energy Carolinas, 410 S. Wilmington Street, Raleigh, North Carolina 27602

For Duke Power Company LLC, d/b/a Duke Energy Carolinas, LLC:

Lawrence B. Somers, Assistant General Counsel, Duke Energy Corporation, 526 S. Church Street, Charlotte, North Carolina 28202

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27602

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

Bernard L. McNamee, III, McGuire Woods LLP, 901 East Cary Street, Richmond, Virginia 23219-4030

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 420, Raleigh, North Carolina 27602

For North Carolina Electric Membership Corporation:

Thomas K. Austin, Associate General Counsel, North Carolina Electric Membership Corporation, 3400 Sumner Boulevard, Raleigh, North Carolina 27616

For Carolina Utility Customers Association, Inc.:

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

For Carolina Industrial Group for Fair Utility Rates:

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

For North Carolina Waste Awareness and Reduction Network:

John Runkle, P.O. Box 3793, Chapel Hill, North Carolina 27515

For Environmental Defense and Southern Environmental Law Center:

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

For North Carolina Sustainable Energy Association:

T. LaFontine Odom, The Odom Law Firm, PLLC, 1109 Greenwood Cliff, Charlotte, North Carolina 28204

For the Using and Consuming Public:

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

Kendrick C. Fentress, Robert S. Gillam, and Tab C. Hunter, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

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

Consistent with the requirements of G.S. 62-110.1, the Commission conducts an annual investigation into the electric utilities' integrated resource planning (IRP). Commission Rule R8-60 requires that each of the investor-owned utilities and the North Carolina Electric Membership Corporation (collectively, the utilities) furnish the Commission with an annual report (annual report or plan) that contains specific information that is set out in subsection (c) of the Rule. In addition, Commission Rule R8-62(p) requires that the utilities incorporate information in these annual reports concerning the construction of transmission lines. Within 90 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own report or an evaluation of or comments on the utilities' reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing.

The General Statutes also require that least cost planning be implemented by the utilities in North Carolina. G.S. 62-2 provides, in part, that it is the policy of the State:

> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills[.]

The Commission has implemented the provisions of these statutes by requiring annual filings by Progress Energy Carolinas, Inc. (PEC); Duke Energy Carolinas LLC (Duke); the North Carolina Electric Membership Corporation (NCEMC); Dominion North Carolina Power (DNCP); and Western Carolina Energy, LLC (WCE). These annual filings set out the utilities' load growth projections and the manner in which the utilities plan to meet anticipated loads.

On August 31, 2005, WCE filed its annual report. On September 1, 2005, DNCP, PEC, and NCEMC filed their annual reports. In accordance with an extension of time granted by the Commission, Duke filed its annual report on November 1, 2005.

The following parties requested and were allowed to intervene and participate in the proceedings: the North Carolina Sustainable Energy Association (NCSEA); the North Carolina Waste Awareness and Reduction Network, Inc. (NCWARN); Environmental Defense and the Southern Environmental Law Center (ED/SELC); the Southern Alliance for Clean Energy, Inc. (SACE); the Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); and the North Carolina Advanced Energy Corporation. The intervention of the Public Staff was recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e), and the intervention of the Attorney General was recognized pursuant to G.S. 62-20.

Pursuant to a motion for extension of time, which was allowed by the Commission, the Public Staff, NCWARN, NCSEA, ED/SELC, and SACE each filed comments on the annual plans on

February 6, 2006. On February 20, 2006, Duke, PEC, and the Public Staff filed reply comments. On March 9, 2006, NCSEA filed additional comments; PEC responded by filing further reply comments on March 22, 2006.

On April 3, 2006, the Commission issued its Order Scheduling Public Hearing and Evidentiary Hearing, Requiring Public Notice, and Establishing Workgroup wherein the Commission scheduled a hearing for public witnesses, scheduled an evidentiary hearing, and formed a workgroup to review specific general issues related to the IRP. The Commission determined that the following issues were best suited for an evidentiary hearing:

1) the validity of the utilities' load forecasting methods;
2) whether the companies are employing and developing adequate DSM and displacing the need for additional generation assets;
3) the potential opportunities for cost-effective energy efficiency and conservation measures, as described in G.S. 62-2;
4) the degree to which utility programs can effectively reduce consumption, including information on the amount of customer education necessary and financial incentives employed by the companies to encourage customer energy efficiency measures; and
5) what funding mechanisms could be employed to implement specific energy efficiency measures.

On May 1, 2006, the Commission held a public hearing in Raleigh. By order issued May 4, 2006, the Commission scheduled two additional public hearings in Greenville and Asheville. Those hearings were held on May 31, 2006, and on June 1, 2006, respectively.

Raleigh Public Hearing

Thirty-four public witnesses testified before the Commission. Included in that number were representatives or members of alternative energy organizations, environmental groups, and members of the using and consuming public, including one elected state official. The following public witnesses testified as representatives of an alternative energy organization or an environmental group: Avram Friedman, Canary Coalition; Norm Miller and Elizabeth Self, North Carolina Sierra Club; Louis Zeller, Blue Ridge Environmental Defense League; Judy Kincaid, Clean Energy Durham; Alice Lloyd and Bob Rodriguez, Climate Connection-North Carolina Council of Churches.

The following public witnesses testified as members of the using and consuming public: Giles Blunden, John Brady, Joyce Brown, Liz Cullington, William Delamar, Susan Delaney, Henry Elkins, Andrew Foglia, Aniko Gaal, E. Thomas Henkel, Chris Hopkins, Herman Jaffe, North Carolina State Senator Eleanor Kinnaird, Samuel Laurie, Mark Marcopolos, John Martin, Mary McDowell, Matthew Meares, Daniel Morris, Thomas O'Dwyer, Chatham Olive, Blair Pollock, Jim Sander, Cindy Pollock Shea, Susan Tideman, Tim Tobbin, and Maurice Werness.

The following individuals were present at the hearing, but, due to time constraints, submitted written statements for inclusion in the record in lieu of testimony: Lynn Pudlo, Ben Scardella, Carla Frisch, Patti Dukes, Barbara Janeway, Steve Halsted, Karen Rindge, Shelly Toth, and Niles Barnes.

The public witnesses testified overwhelmingly in favor of energy conservation and efficiency and urged an investment in renewable energy resources, as opposed to an investment in additional generating facilities. Many of the witnesses brought up the perceived risks of nuclear power to the health of North Carolina residents and to the environment. Witnesses from the North Carolina Sierra Club suggested improved lighting systems as a way to cut demand for energy. Other witnesses strongly opposed coal power and nuclear power. Witnesses representing Clean Energy Durham and Climate Connection-NC Council of Churches Interfaith Power and Light suggested several energy efficiency options to reduce global warming, such as energy audits, use of Energy Star appliances, improved lighting systems, and renewable energy sources. The public witnesses also suggested a public benefit fund to finance energy efficiency measures statewide.

Greenville Public Hearing

Three public witnesses testified before the Commission. Bill Kloepfer, testified that he was associated with the North Carolina Sierra Club. Dave Cavellini and Joan Lintelman also testified. As with the Raleigh public hearing, these witnesses were very much in favor of energy conservation, energy efficiency and the use of renewable energy resources, as opposed to building new power plants.

Asheville Public Hearing

Thirty-nine public witnesses testified before the Commission. Many of the public witnesses were associated with alternative energy organizations or environmental groups: Mary Love, Eco-Certified Realtors; Margie Meares, Clean Air Community Trust; Ned Ryan Doyle, Southern Energy Environment Expo; Elizabeth O'Nan, Blue Ridge Environmental Defense League; Lewis Patrie and Don Richardson, Western North Carolina Physicians for Social Responsibility; Jody Flemming, Western North Carolina Alliance; Grant Millin, Public Fuel Cell; Susan Stewart and William Thomas, North Carolina Sierra Club; Tabitha Reyes, Home Energy Partners; Ken Huck, Sustainable Building Energy Solutions; and Carol Stangler, Nuclear Watch South, formerly Georgians Against Nuclear Energy.

The following public witnesses also testified as members of the using and consuming public: Clay Ballentine, M.D., Ske Boniske, Ian Booth, John Butcher, Kim Carlyle, Ruth Clark, Marianne Coats, Claudine Cremer, Dee Eggers, Robert Eidus, Richard Fireman, Bill Fisk, Peggy Guy, Norma Ivey, David Johnson, Charles Krug, Bill Lyons, Mary Olson, Redmoonsong, Eva Ritchey, Peter Sipp, Dot Sulock, John Stiopewich, Keith Thompson, Jones Tysinger, and Tom Weinkam.

The following individuals were present at the hearing, but, due to time constraints, submitted written statements for inclusion in the record in lieu of testimony: Tim Campbell, Jenny Mercer, Dale Carroll, David Barbee, Thomas Coulson, Anne Craig, Ray Denny, Scott Hamilton, Michael Hopping, David Johnson, Joan and Franklin Palmroos, Sam Powers, Matthew Siegel, Nancy and Sebastian Sommer, Marie Spengler, and Steven Williams.

As with the first two public hearings, witnesses appearing in Asheville were overwhelmingly committed to energy conservation, demand reduction, and renewable energy resources as alternatives to the construction of additional power plants. Some public witnesses suggested a change in the rate structure to reward customers who reduced their demand for energy. Others discussed the risk of nuclear power being used to make weapons. The public witnesses also proposed green building of residences and businesses and recommended Energy Star appliances to reduce the demand for energy.

The Commission also received more than 100 letters and e-mails from customers describing how they had reduced their energy consumption, expressing strong support for energy conservation, and urging the Commission to pursue efficiency and renewable sources of energy as integral elements in the utilities' current planning.

In sum, more than seventy public witnesses appeared to testify before the Commission on their strong beliefs that North Carolina should become more energy efficient and less reliant upon non-renewable sources of energy in order to protect our citizens' health and the environment.

On June 21, 2006, PEC, Duke, and DNCP filed a motion to strike all or parts of the prefiled testimony of four witnesses submitted by NCWARN and NCSEA.

The matter came on for an evidentiary hearing on June 27, 2006, as previously noted and scheduled. Herman Jaffe testified as a public witness, endorsing energy conservation and expressing his concern over mercury from the utilities poisoning the environment. After hearing argument on the motion to strike, the Commission denied the motion. Duke, PEC, and DNCP presented the testimony of Julius Wright, Ph.D. Duke also presented the testimony of a panel of witnesses consisting of Richard G. Stevie, Ph.D, General Manager of Market Analysis for Duke Shared Services, and Janice Hager, Vice President, Rates and Regulatory Affairs for Duke.

PEC presented the testimony of its panel of witnesses, Samuel S. Waters, Director of System Resource Planning, B. Mitchell Williams, Manager of Regulatory Affairs, and Michael T. Ligett, Director of Market and Energy Services.

DNCP presented the testimony of its witnesses in a panel consisting of David F. Koogler, Director-State Regulation, and Md. Shamsul Huq, Ph.D., Lead Economist.

NCEMC presented the testimony of David Beam, Senior Vice President of Corporate Strategy for NCEMC.

CIGFUR presented the testimony of Nicholas Phillips, Jr., a consultant with the firm of Brubaker & Associates, Inc.

CUCA presented the rebuttal testimony of Kevin O'Donnell, President of Nova Energy Consultants, Inc.

ED/SELC presented the testimony of William R. Prindle, Deputy Director of the American Council for an Energy Efficient Economy.

NCSEA presented the testimony of Jeffrey S. Tiller, Professor at Appalachian State University, and the panel of Derrick Giles, President of Enpulse Energy Conservation, and Jim Parker, Director Energy Management Program.

NCWARN presented the testimony of its witnesses in a panel consisting of John O. Blackburn, Ph.D., Professor Emeritus of Economics, Duke University, Alicia O. Ravetto, AIA Architect, and Paul W. Konove, President of Carolina Country Builders of Chatham County, Inc.

SACE and Advanced Energy did not participate in the evidentiary hearing.

The following parties submitted briefs and/or proposed orders on August 11, 2006: PEC, Duke, NCEMC, DNCP, NCWARN, ED/SELC, CUCA, CIGFUR, the Public Staff and the Attorney General. Also on August 11, NCSEA submitted a list of findings of fact, stating that it would file supporting evidence on or before August 18, 2006. This information was, in fact, filed on August 18, 2006 along with a motion asking the Commission to accept the late filing, which is allowed.

Based upon the foregoing, the information contained in the utilities' annual plans, the testimony and exhibits introduced at the hearings, and the Commission's record of this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. The utilities use accepted methods to forecast their peak demand and energy sales needs.

2. The utilities subject to the Commission's IRP rules have complied with R8-60(c)(9), which requires only that each utility include a list of the demand-side management (DSM) options reflected in their resource plans.

3. Proposals for new baseload generation capacity, higher energy costs, and less interest in deregulation of the electric industry in North Carolina have revitalized interest in energy efficiency and conservation such that additional review and evaluation of DSM programs are warranted.

4. The utilities' development and deployment of DSM resources for the purpose of displacing the need for additional generation assets is adequate for the 2005 IRP, but may not be adequate for future proceedings.

5. Numerous opportunities exist for the development of cost-effective energy efficiency and conservation measures.

6. The degree to which utility programs can effectively reduce consumption cannot be determined with precision at this time. However, it is materially less than the total potential for energy conservation, because the decision whether to take advantage of energy conservation opportunities must be made individually by each customer. The amount of customer education necessary, and the appropriate and reasonable amount of any financial incentive to be made available, must be carefully considered with respect to each energy conservation program offered.

7. Numerous funding mechanisms exist to encourage energy efficiency, including but not limited to riders added to other rates for utility service, public benefit funds to subsidize customer expenditures, and deferral accounting mechanisms.

8. The utilities' 2005 annual plans are reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the testimony of Duke witness Dr. Stevie, the testimony of Dr. Wright, the testimony of DNCP witness Dr. Huq, the testimony of

NCEMC witness Beam, the testimony of CIGFUR witness Philips, the testimony and exhibits of ED/SELC witness Prindle, the testimony and exhibits of NCWARN witness Blackburn, and the utilities' annual plans.

Witness Wright, testifying on behalf of PEC, Duke, and DNCP, stated that the forecasted growth rates for those utilities' peak loads were reasonable. He found that the forecasts were consistent with prior years' forecasts, that the forecasts were generally equivalent to the Energy Information Administration's southeast region forecasts, and that PEC, DUKE, and DNCP employed forecasting methodologies previously approved by this Commission.

Duke witness Stevie testified that Duke's peak demand and energy sales forecasts are reasonable and appropriate for preparing its resource plan. The forecast methodology is the same as used in prior annual plans filed with the Commission. Dr. Stevie noted that the primary factors used in the econometric models are the number of customers, weather, energy price, employment, industrial production, and income.

Dr. Stevie disagreed with the contention that Duke's load forecast fails to incorporate properly end-use energy efficiency. He testified that past trends of increasing energy efficiency are captured in the historical data and reflected in the coefficients developed for the forecasting models and the subsequent forecast. Dr. Stevie noted that NCSEA witness Prindle's recommendation would require the utilities to incorporate a forecasting technique that would allow the forecasts to be altered by an assumed level of future market penetration from an assumed level of future energy saving appliances and homes. Dr. Stevie further disagreed with Dr. Blackburn's findings that the predicted growth rate of Duke's commercial demand may be overstated. He maintained that the stated growth rate in Duke's annual plan was 2.8%, not 3.5%, and that the difference in the growth rates is not that significant.

The PEC panel of witnesses likewise testified that PEC's forecast methodology is the same as used in prior annual plans filed with this Commission. The PEC panel noted that the primary factors used in the models are the number of customers, weather, energy prices, employment, personal income, population, and housing stock. The PEC panel disagreed with NCWARN witness Dr. Blackburn's supposition that PEC's forecast is too high due to the increasing efficiency of newer homes. The panel noted the increasing size of homes and the increasing number of large televisions, computers, and other electric appliances being used today. The panel opined that the increase in energy efficiency is offset by the increase in the average home size and in the average use per home associated with those appliances, and that PEC's forecast implicitly incorporates these trends in energy efficiency and use.

Dominion witness Huq testified to the validity of DNCP's peak demand and energy sales forecasts. He stated that DNCP has used a standard general method for the past two decades and that the results have been satisfactory and accepted by various regulatory authorities.

NCEMC witness Beam testified to the validity of NCEMC's peak demand and energy sales forecasts.

CIGFUR witness Philips testified that the utilities have presented reasonable load forecasts, which are continually reviewed, modified, and improved over time.

In regard to Duke's and PEC's forecasts, ED/SELC witness Prindle testified that those forecasts are deficient in that they lack documentation on energy efficiency programs. He also questioned how the energy efficiency programs have been integrated into their plans. Witness Prindle noted that forecasting methods should reflect the impacts of the new 2006 residential and commercial air-conditioning standard, and he suggested that Duke should account for its new Energy Star homes and appliance programs in forecasting peak demand as well as electricity sales. In addition, witness Prindle testified that the filings should contain adequate documentation on the impacts of DSM and energy efficiency programs on the forecast. He was unable to find any documentation on the assumptions, data inputs, and calculation methods used to produce any estimates on the impacts of energy efficiency programs. Furthermore, witness Prindle testified that the failure to quantify the impact of energy efficiency programs in the load forecast is insufficient for proper resource planning. With regard to PEC's forecasts, witness Prindle likewise expressed similar concerns about the lack of documentation of energy efficiency programs and how they may have been integrated into PEC's annual plans.

NCWARN witness Blackburn testified that the 3.5% predicted growth rate in Duke's gigawatt commercial sales may be overstated. Dr. Blackburn maintained that the recent growth in commercial electricity, which has displaced the use of other fuels, is likely to decrease in the future. Furthermore, Dr. Blackburn cited a 2003 study by the Department of Energy that predicted an annual growth rate for commercial sales at 2.5%.

In his testimony, Dr. Blackburn described the very large scope for conserving electricity and using it more efficiently. Dr. Blackburn testified that the two utilities analyzed, Duke and PEC, project in their IRPs additional energy sales of approximately 26 billion kWh in 2015. He estimated that a vigorous conservation efficiency effort in the residential and commercial sectors could realize annual savings of approximately 12-13 billion kWh by 2015 for the two utilities. Dr. Blackburn further testified that another 5.5 billion kWh appears to be an overstated projection for commercial electricity. Industrial savings and cogenerated electricity can supply another significant share of savings and, on top of that, renewable energy technologies, including some contribution from each of the in-state sources, can supply any needed generating capacity. Dr. Blackburn concluded that, based on all of the above, the need for large and expensive new plants can be postponed for years, if not eliminated altogether.

NCWARN is convinced that an investigation of the growth in demand, if done fairly and in consideration of all sectors, will result in the recognition that no new generation plants are needed because they are too costly and too risky and would preclude the cleaner and safer alternatives.

The Public Staff comments, which were filed on February 6, 2006, are directed at the ten-year (2006-2015) growth rates in the utilities' peak demand and energy forecasts and a three-year and five-year review of the accuracy of the utilities' previously filed forecasts. The Commission notes that the Public Staff determined that all of the utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. In its comments, the Public Staff noted that Duke had predicted a sharp increase in its wholesale sales in 2011. After the February 6, 2006 filing, the Public Staff has learned that a portion of the 2011 increase in Duke's wholesale sales is no longer expected. Thus, after incorporating this reduction in wholesale sales, Duke's forecast would reflect a 1.9% average annual growth rate in its summer peak with an average annual growth of 348 MW, a 1.1% average annual growth rate in its winter peak, and a 1.7% average annual growth rate in its energy sales. With these revisions to Duke's forecasts, the Public Staff's proposed order indicated that it had concluded that the peak and energy forecasts by the utilities were reasonable and appropriate for use in their annual plans.

The Commission is not persuaded by Dr. Blackburn's contention that Duke's and PEC's forecasts are overstated. Furthermore, the Commission is not convinced that Duke's and PEC's forecasts are insufficient for resource planning because the models do not explicitly allow for an adjustment due to new appliance standards and other efficiency programs. Nor is the Commission persuaded that the utilities need to revamp their forecasting methodologies. The Commission urges the utilities to consider applying additional end-use data in their forecasting models that would allow for recognition of factors, such as the recent changes in appliance efficiency standards, that would not necessarily be reflected in the historical economic and demographic data. While the Commission acknowledges that end-use forecasts can provide useful information, the Commission is not convinced, based on the record developed in the instant proceeding and past proceedings, that end-use forecasts provide superior forecasts to econometric methods, particularly in light of the added costs. In view of the evidence presented, the Commission finds that the methods employed by the utilities are valid for use in this proceeding.

The Commission notes, however, that both NCWARN and Commissioner Culpepper questioned Dr. Wright about the impact of the utilities' wholesale commitments on their predicted growth rates for their peak load forecasts. In its proposed order, the Public Staff recommended that the Commission require additional information with respect to the wholesale sales contracts. In view of these concerns, the Commission concludes that the utilities' future annual plans should provide the following: the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of MWs on an annual basis for each such contract, the length of each contract, and the type of each contract (e.g., native load priority, firm). If such information is not included in the 2006 plans when filed, the plans shall be supplemented with the information within 60 days.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2- 4

The evidence supporting these findings of fact is contained in the utilities' 2005 annual reports, the testimony of the public witnesses, the testimony and exhibits of witness Wright, PEC's panel of witnesses, Duke witness Hager, DNCP witness Koogler, NCEMC witness Beam, CIGFUR witness Phillips, CUCA witness O'Donnell, NCWARN witness Blackburn, ED/SELC witness Prindle, and the testimony and exhibits of NCSEA witnesses Edgar and Giles.

Witness Wright described the IRP process in North Carolina during the time he was a member of this Commission from 1985 to 1993. The IRP process initially involved a significant amount of time and resources when it was begun in 1988. According to Dr. Wright, this process became too cumbersome as fuel and capacity costs declined in the 1990s, as electric competition was introduced, and as the need for new generation resources decreased. Moreover, lower fuel costs and new generation technologies during the 1990s rendered many DSM programs less cost-effective than before. In 1998, therefore, the Commission reduced the IRP rules and requirements, and those streamlined rules and requirements remain in force today. Dr. Wright quoted from the 1998 Commission order adopting the streamlined rules, stating that

> [t]he IRP process dates from an earlier era and presupposes a monopoly for the utilities in the generation of electricity. As the industry evolves . . . new regulatory

mechanisms may need to be developed. At this time, however, the Commission chooses to keep the IRP process *narrowly* focused on the requirements of the statute.

Dr. Wright testified that he and an associate had reviewed the utilities' annual plans for 2005 and found that they were reasonable and in compliance with the statutes and rules governing the IRP process. Based on the results of his review, Dr. Wright testified that the utilities are using the full spectrum of DSM options, as the law requires. In support of his conclusion, Dr. Wright testified that he interviewed personnel at the utilities and reviewed their ongoing DSM activities. He reported that PEC, Duke, and DNCP had used DSM peak load reduction programs that reduced their 2005 projected summer peaks by 374 MW, 722 MW, and 29 MW, respectively. Both PEC and Duke conduct an initial screening of options to identify practical and reliable resources, review potential DSM or renewable options and their respective costs, conduct an initial cost screening to identify potential options, and then implement sophisticated industry standard computer models to develop their final optimal resource plans. Dr. Wright concluded that their resource comparisons were reasonable. He noted that PEC and Duke were phasing out some DSM programs, such as water heater and HVAC controls, because they (1) are aging and lack supplier support for the existing technology and (2) lack customer acceptance. Both PEC and Duke, however, are re-examining the costs, customer acceptance, and benefits of these and other load control programs.

Dr. Wright further testified that DNCP's planning process is influenced by its membership in PJM, its active participation in the competitive wholesale market, and the deregulation of generation and the existence of retail competition in Virginia. The marketplace realities allow DNCP to produce supply-side benefits for its North Carolina ratepayers; at the same time, DNCP provides DSM programs to those same ratepayers.

With regard to PEC specifically, Dr. Wright testified that it currently has 19 DSM programs, encompassing customer education, energy efficiency programs, interruptible rates, time-of-use rates, and discounts for energy efficiency. Dr. Wright testified that the list of DSM programs included in PEC's 2005 annual report does not actually reflect all of PEC's DSM activities; he would have counted the programs differently. For example, Dr. Wright counted PEC's support of Advanced Energy and NC GreenPower as DSM activities. PEC has also initiated a new team effort looking at both additional DSM and renewable energy options, starting with a database of 1,200 DSM programs.

Dr. Wright's discussions with Duke indicated that it has 15 to 20 ongoing DSM programs similar to PEC, and that it has likewise undertaken a more focused effort on acquiring more cost-effective DSM and renewable energy sources. An outside firm performed a study for Duke that examined various DSM programs and their costs. Dr. Wright acknowledged that Duke has only listed 11 DSM programs in its 2005 annual report, but he counted certain DSM programs as two distinct programs if they were offered to two different customer classes.

Discussions with DNCP indicated to Dr. Wright that it has several DSM programs, including approximately six consumer education programs, one residential energy discount program, some curtailable service programs, and several additional tariff-based DSM programs, such as time-of-use rates. Dr. Wright concluded that DNCP's resource planning process is reasonable.

According to Dr. Wright, changing conditions in the electric industry compelled PEC's and Duke's renewed focus on DSM options in the last year. He explained that, when utilities begin to consider adding new baseload facilities and when fuel costs are higher, DSM programs become more important and more cost-effective. This does not mean, however, that they will displace the need for new generation plants or that a utility will necessarily choose to implement more DSM programs than it was already using. Furthermore, accurately estimating a future load reduction based on a DSM program takes a great deal of time and money. Even if another state, such as Wisconsin, has performed a cost/benefit analysis for a DSM program and found that the benefits of the program outweighed the cost of building more generation, Dr. Wright cautioned that the results of that study would not necessarily transfer to North Carolina. He believed that a study using North Carolina data could be done, but that to do so would involve determining what kind of DSM program was to be used, whether customers would accept it, and whether a pilot program is needed. Dr. Wright also disagreed with the assertion that, if more energy efficiency programs had been used over the past ten years, no new capacity would be needed now. He asserted instead that the utilities must build electric resources sufficient to meet the demand. Even if everyone insulated their homes and adopted energy efficiency measures, North Carolina is still adding more than 100,000 people a year to its population, and the population is building bigger houses and buying more appliances. Load is growing faster than DSM programs are reducing the load or potentially reducing the load. Therefore, Dr. Wright concluded, sooner or later, the utilities will have to build new or more generating facilities. There is no "magic silver bullet" to reduce North Carolina's growing demand.

Dr. Wright next compared North Carolina's current IRP process to those in neighboring states. Based on his comparison, he concluded that North Carolina is re-examining the IRP process and pursuing DSM programs in a reasonable and timely fashion. North Carolina's actions are similar to, if not more proactive than, those in neighboring states.

The Commission will now summarize the evidence put forth by other parties:

PEC

The PEC panel, consisting of Samuel S. Waters, B. Mitchell Williams, and Michael T. Ligett, testified in more detail regarding PEC's implementation of DSM options and its need for additional generation in the future. The PEC 2005 annual plan includes proposed generation additions that are generic resources included in the plan solely to indicate the need for additional generation resources; no commitments as to type, amount, location, or ownership of the needed capacity have been made. PEC presently has no request pending before the Commission seeking approval to build any specific generating facility.

The panel listed and described approximately 11 energy conservation programs, including, but not limited to, various online services that provide tools and information for consumers about reducing their energy consumption and bills, residential energy evaluations and recommendations on how to manage home energy costs, and energy efficient home building programs and financing. The panel also described approximately four demand response programs. These time-of-use and real time pricing rates stimulate customers to curtail usage during on-peak, high-cost time periods. The panel estimated that PEC's energy conservation programs have reduced energy consumption by PEC's customers by approximately 16 billion kWh since 1981. In addition, the peak load reduction potential associated with conservation, demand response, and load control programs is estimated to be more than 950 MW currently. PEC has discontinued some DSM programs over the years. As fuel and financing costs moderated in the 1990s and as building codes and appliance efficiency standards evolved, some existing programs were no longer cost-effective. Increasing fuel costs coupled with the costs for new generation and the potential for more stringent air emissions limits, however, have compelled PEC to reexamine DSM options. The panel testified that PEC's energy efficiency programs resulted in energy savings of almost 2% of annual energy sales in 2003, but PEC expects to increase that percentage if it finds additional cost-effective DSM options in the future.

The panel next testified about its present process for screening DSM programs by computer model. This computer model was not part of the record in this case because it is proprietary and access is only granted through confidentiality agreements with the vendor. However, PEC had arranged such agreements in the past for people who wanted to have access to the model. First, PEC inputs the scheduled units to be built. Then PEC enters the DSM programs individually. PEC performs the Rate Impact Measure (RIM) and Total Resource Cost (TRC) tests within its computer model, as well as the Participant Test separately. Programs that eventually pass those tests will be combined so that there will be sufficient DSM to avoid generation. PEC witness Waters testified that the RIM test was "obviously one of the major guidelines we use to determine what goes into the final plan"; however, in some situations PEC would consider a program that fails the RIM test by a narrow margin but passes other tests such as TRC.

Duke

Duke witness Janice D. Hager testified regarding Duke's DSM in its 2005 annual plan and about its plans for DSM going forward. Duke classifies its DSM programs as either demand response or energy efficiency. Duke's current demand response programs include load curtailment, interruptible power service, standby generator control, and residential service controlled water heating. The load curtailment programs include residential air conditioning direct load control with approximately 190,000 customers and residential water heating direct load control with approximately 35,000 customers. The interruptible programs include approximately 150 commercial and industrial customers with interruptible power service and 150 commercial and industrial customers with standby generator control. These interruptible programs reduce summer 2006 capacity needs by an expected 766 MW. Duke's structures its time-of-use rates so that customers can reduce energy bills by shifting load from on-peak to off-peak hours, thereby helping Duke to avoid the need for new generation.

Ms. Hager also testified that Duke's energy efficiency programs include Energy Star, which promotes the development of homes that are significantly more energy-efficient than standard homes. Duke also provides loans to encourage increased energy efficiency in existing homes. As a result of the Commission's approval of Duke's merger with Cinergy, Duke is investing $2,000,000 in conservation and energy efficiency programs approved by the Commission.

Ms. Hager described DSM as a "valuable tool" in managing Duke's customers' demands for capacity and energy. Duke conducted a "head-to-head" comparison of supply-side and demand-side resources for its 2005 annual plan. Demand response programs can offset the need for peaking capacity, and they will represent approximately 25% of Duke's reserve margin in 2010. Energy efficiency and conservation programs can also reduce the amount of needed intermediate and baseload capacity. Ms. Hager testified that the impact from DSM is difficult to quantify, but it has resulted in lower baseload and intermediate capacity needs than would have been required without the DSM programs.

Ms. Hager further testified that, in preparation for its 2005 annual plan, Duke considered the following potential demand response programs in the planning process: (1) direct load control, (2) interruptible service, (3) standby generation, and (4) energy efficiency programs. Duke also considered bundles of energy efficiency programs by customer class at increasing costs. Duke's analysis revealed potential cost-effective demand-response resources; therefore, Duke's annual plan includes 100 MW of expected demand response program capability by 2009. Duke's analysis did not identify, however, any specific cost-effective energy efficiency resources, because the programs would have resulted in lower energy bills for participating customers, while non-participating customers would bear the costs. In other words, the programs would have resulted in cross-subsidization. Nevertheless, Ms. Hager opined that Duke had employed adequate DSM programs.

Ms. Hager acknowledged that the evaluation of DSM resources is a part of least cost planning, but indicated that the cost data on DSM resources and Duke's DSM resource screening methodology is not in Duke's 2005 annual plan. She explained that the Commission's rules on annual plans do not require the utilities to provide that information in their annual plans. According to Ms. Hager, if the Commission or any other party requires this information, it can request it from Duke.

DNCP

DNCP witness David F. Koogler testified that DNCP classifies DSM in two basic categories: (1) DSM education programs, outside the tariff pricing regime, that educate or promote energy efficiency or conservation and (2) tariffs that either include direct load control provisions or provide time-differentiated pricing. Mr. Koogler testified that DNCP believes that tariff-based DSM, particularly dynamic pricing tariffs, enables customers to make energy-efficient purchasing decisions. In addition to those DSM programs listed in its annual plan, DNCP continues to employ both DSM education programs and tariff-based DSM to reduce or manage consumption, thereby ultimately limiting the demand for generation.

At the evidentiary hearing, Mr. Koogler filed testimony that DSM programs are not waning, but are evolving. DNCP believes that combining customer education with cost-effective energy efficiency programs and pricing options provides customers with incentives to decide how to use electric energy. With respect to customer education, DNCP includes energy savings tips in a customer newsletter, notifies customers once a year of all the available rate schedules, including dynamic pricing schedules, and posts energy saving tips on its website. DNCP's DSM options consist of three direct load control programs: Residential Water Heater Load Control, Nonresidential Standby Generation, and Nonresidential Curtailable Service programs. Mr. Koogler testified that these programs are forecast to reduce the summer peak load forecast by 29 MW and the winter peak load forecast by 26 MW in 2006. Mr. Koogler further testified that DNCP has had time-of-usage (TOU) rates in some form since the late 1970's. Two TOU rates are available to North Carolina residential customers, and DNCP also offers TOU rates to its small and large general service customers. Further, DNCP has agreements for electric service with one large industrial customer in North Carolina that involve dynamic pricing and curtailment provisions during high cost and load periods. In sum, Mr. Koogler testified that more than 35% of the energy supplied to customers in the North Carolina service territory is provided under some form of dynamic pricing tariff. Customers served under these tariffs reduced their demand approximately 225 MW during high cost periods of their respective tariffs.

NCEMC

NCEMC witness David Beam testified that NCEMC invested in a statewide load management system in the mid 1980s. This system uses radio signals that communicate with switches installed to control residential air conditioners and water heaters across the State and to communicate control signals to customer owned generation resources. In combination, these resources have provided the capability to reduce system demand by more than 200 MW during peak periods. Mr. Beam further testified, however, that because this infrastructure was installed about 20 years ago, much of the equipment has become obsolete and difficult to replace. Therefore, NCEMC is investigating ways to cost-effectively extend the work of the current system. NCEMC also actively promotes energy conservation to its customers with a range of programs including education, research, energy audits, and rebate programs. As with Duke and PEC, NCEMC contributes to NC GreenPower.

CIGFUR

CIGFUR witness Nicholas Phillips, Jr., testified that increased conservation and DSM activity by North Carolina ratepayers does not translate into automatic reductions in the need for generation by the utilities. The output from generation plants in North Carolina is influenced by off-system, often out-of-state, sales. Therefore, reduced consumption by North Carolina ratepayers may simply result in the utilities selling more of their power to other markets.

ED/SELC

In its August 11, 2006 brief, ED/SELC states that the plans filed by Duke and PEC violate both the letter and the spirit of G.S. 62-2, in which the General Assembly set forth our State's policy regarding least-cost resource planning. Further, the Duke and PEC plans fail to comply with the *de minimis* requirements outlined in NCUC Rule R8-60, including Rule R8-60's requirement that the plan include a list of demand-side options reflected in the plan. In addition, to the extent that it can be determined given the lack of detail on DSM options, the plans betray an over-reliance on nonrenewable supply-side options, to the detriment of DSM and particularly energy efficiency options. According to ED/SELC, the plans reveal that the utilities are not achieving the least-cost mix of generation resources available, in contravention of G.S. 62-2.

ED/SELC witness William R. Prindle testified that, while the utilities' annual plans may comply with Commission Rules R8-60 and R8-62(p), they do not show that the resources used to meet future growth include the entire spectrum of DSM options as required by G.S. 62-2(3a). His review of the annual plans of Duke and PEC revealed no substantive, quantitative analysis of energy efficiency's role in resource planning and few significant energy efficiency measures. The plans fail to show any assessment of energy efficiency potential, any evidence of comprehensive energy efficiency screening, or any assessment of market factors that would affect energy efficiency programs. Mr. Prindle acknowledged that Duke witness Hager had testified that she conducted a quantitative comparison between supply and DSM resources, but he was unsure what data had been used.

Mr. Prindle noted that Duke's plan in particular lacked energy efficiency programs compared to the demand response programs included in the report. Duke's plan did not contain quantification of energy sales impacts from DSM programs or any details on efficiency program design or design criteria. Duke's DSM numbers in its annual plan appear to reflect only load management/demand response programs that reduce peak loads for short periods. Of Duke's listed DSM programs, eight are load management, and four are energy efficiency. He also disagreed with Dr. Wright's testimony that Duke has 15-20 ongoing DSM programs; Mr. Prindle counted only 11 DSM programs reflected in Duke's annual plan. In addition, Mr. Prindle disagreed with Duke's classification of Residential Service Water Heating as an efficiency program because it shifts load to off-peak hours. There are no commercial or industrial programs listed, even though the majority of energy efficiency potential exists in those types of programs. The Energy Star program only covers new homes, despite the number of other Energy Star products that could have been included. Furthermore, Duke has provided an expected total annual 715,927 MWh reduction. Mr. Prindle testified that 715,927 MWh represents 0.9% of Duke's regular sales forecast for 2006. He noted that in other states energy efficiency has been able to reduce forecast electricity sales by 24%. Mr. Prindle further explained that a DSM program's full potential cannot be reached in one year alone, but can be reached in 10-20 years. Mr. Prindle urged that efficiency programs begin early in the IRP planning process.

As for PEC's annual plan, Mr. Prindle stated that it was similar to Duke's in the lack of documentation of energy efficiency resources and their integration into the IRP. Mr. Prindle disagreed with Dr. Wright's testimony that PEC has approximately 19 different DSM programs. Mr. Prindle counted only seven DSM programs reflected in PEC's annual plan.

Mr. Prindle further testified that, according to the American Council for an Energy Efficient Economy (ACEEE) Scorecard report, North Carolina ranks 46th among the states on utility efficiency program spending per capita, 46th on program spending as a percent of revenue, and 47th on program energy savings as a percentage of energy sales. This ranking does not recognize, however, the energy efficiency programs of Advanced Energy. When the impact from those programs is added to the equation, North Carolina ranks 35th in spending per capita and 35th in spending as a percentage of utility revenue. He testified that these rankings show that North Carolina has room for improvement.

According to ED/SELC, Duke and PEC have filed "business-as-usual" plans that fail to include meaningful DSM measures and are particularly deficient in their lack of energy conservation and efficiency measures. In addition, the plans do not discuss DSM measures in any detail, fail to explain how DSM measures were screened and selected, and fail to quantify the impacts of existing or planned DSM measures. ED/SELC urged the Commission to refrain from approving the Duke and PEC 2005 plans until those utilities correct the deficiencies in their plans.

NCSEA

NCSEA witness Edgar testified that, based upon his review of the information filed by the utilities in this docket, current utility DSM programs fail to adequately capture meaningful cost-effective energy efficiency savings opportunities in North Carolina that would affect the timing and need for future supply-side additions. The DSM programs identified by the utilities contain both load management and energy efficiency programs. However, the energy efficiency programs are mostly informational. While these types of programs are an integral part of a robust IRP, they are inadequate here to capture energy efficiency savings effectively. Moreover, these programs are not comprehensive because they do not offer efficiency savings to all customer classes and submarkets, such as working poor families. Witness Edgar pointed out that, while the load management programs listed in the annual reports can increase reliability and address the growth in peak demand, they actually save little energy. Alternatively, comprehensive and effective energy efficiency efforts can reduce a utility's load curve over the duration of that curve.

Mr. Edgar, however, was unable to identify any state that was currently planning not to add any form of generation in the next ten years. On cross-examination by PEC, he agreed that, if PEC was adding approximately 25,000 new residential customers annually in North Carolina, it would be surprising if PEC could continue to meet its load obligation for an additional ten years without adding any new supply-side generation.

NCSEA witness Giles testified that, while the utilities appear to be implementing a broad range of programs to disseminate information to consumers, it is unclear how effective these programs have been. Better tracking and increased attention would probably make these programs more effective.

NCWARN

Based on the testimony and evidence, NCWARN urged the Commission to declare the plans, and in particular those filed by Duke and PEC, insufficient as they do not provide adequate information and analysis for the Commission to meet its mandate. NCWARN stated that it is difficult to assess the Duke and PEC DSM programs, either current or future, as they have not been presented as part of the IRPs. There are no reports on the energy efficiency that any of the programs have accomplished or any projections of any future savings, nor are there any considerations of renewable energy sources. As such, the plans do not provide a realistic look at all of the demand-side tools available to the utilities; all projected growth is met with costly, conventional power plants.

NCWARN witness John O. Blackburn testified that the most abundant renewable sources, wind and solar electricity, are not considered adequately in the plans. North Carolina has substantial wind resources and is now the only resource-rich state which is not yet developing them. Solar electricity is expensive in some applications, but has enjoyed declining costs and may already be economic at summer peak times. Solar hot water is ideal for North Carolina and complements the benefits from wind energy. These and other clean energy sources are not addressed in the plans.

The Commission has carefully considered all of the testimony. One of the questions posed by the Commission for the evidentiary hearing was "whether the companies are employing and developing adequate DSM and displacing the need for additional generational assets." As noted above, the policy of North Carolina is to assure that the resources necessary to meet future growth through the provision of adequate, reliable utility service include the "entire spectrum" of DSM options, including but not limited to conservation, load management, and efficiency programs. G.S. 62-2(3a). The Commission implements this policy, in part, through its rules on the IRP process. Commission Rule R8-60(c) requires that each utility file an annual report to assist the Commission and Public Staff in their analysis of the long-range needs for expansion of electric generating facilities in North Carolina. That rule further sets out what the companies must include in these annual reports. Specifically, Rule R8-60(c)(9) requires simply that the companies include "[a] list of demand-side options reflected in the resource plan."

As reported in the Public Staff's comments, all of the utilities complied with Rule R8-60(c)(9) in their 2005 annual reports. None of the intervening parties produced any evidence showing that the utilities did not comply with the rules as written. Several witnesses, however, did fault the annual plans for their lack of comprehensive information regarding DSM options, and the Commission notes that the utilities did not list any new programs in their annual reports. Furthermore, the Commission agrees with ED/SELC's witness that the plans of Duke and PEC reveal no substantive, qualitative analysis of energy efficiency measures for 2005. In sum, the 2005 lists of DSM options were substantially the same as the 2004 and 2003 lists.

Several intervenor witnesses suggested that, despite a recently increased interest in DSM, the utilities' 2005 annual reports show an inadequate development of DSM. For example, there was much debate regarding the appropriate test, such as the RIM test or the TRC test, to assess the cost-effectiveness of energy efficiency programs and also how crucial the choice of test or tests can be in deciding whether a DSM program is cost-effective. Several intervenors suggested that, in general, the utilities rely too heavily on the RIM test in their assessment. ED/SELC witness Prindle recommended that the utilities instead employ the TRC test. The RIM test used by the utilities tended to show that many DSM programs were not cost-effective. The application of the TRC test, however, would have resulted in broader DSM efforts. While this is a significant issue, the Commission has delegated the question of the criteria that the Commission should consider in deciding to approve a DSM program in the future to the collaborative workgroup. Therefore, the Commission will not approve or disapprove the tests that a utility employs in its analysis of DSM programs at this time.

Evidence brought out at the evidentiary hearing showed that the utilities consider and evaluate DSM options in greater detail than the annual plans actually show. While there was disagreement concerning the degree to which the utilities are deploying and developing DSM options, the utilities' testimony showed that they evaluated DSM options and incorporated those that were shown to be cost-effective into their annual plans. While it is true that the Commission rules do not require that this information regarding screening and evaluation be included in annual plans, the Commission found this testimony extremely helpful in assessing whether the utilities include the entire spectrum of DSM options in their least cost planning.

The question of whether or not the DSM programs currently are displacing the need for additional generation is difficult to answer. The utilities' witnesses discussed how DSM had reduced energy consumption by their customers, thereby reducing peak, intermediate, and base load needs. There was general agreement among the parties that DSM programs can and have offset the need for peaking capacity, and that they can potentially defer the need for additional intermediate and base load capacity. The Commission believes that the DSM programs implemented in North Carolina in the past have helped to reduce the need for additional generation. The Commission is also mindful of North Carolina's growing population and its increasing demand for electricity, as homes increase in size and in number of appliances. The utilities have an obligation to meet that demand, and the Commission has an obligation to ensure that demand is met reliably.

The evidence further shows that, while the utilities' development and employment of DSM programs are adequate for purposes of the 2005 annual plans, a renewed focus on DSM is now necessary. Duke and PEC conceded as much when they testified that they had recently "reinvigorated" their DSM efforts. The numerous public witnesses and their demands for greater energy conservation and efficiency further indicate that DSM has become much more significant to this process. In the 1970s and 1980s, electric costs escalated due to the Clean Air Act of 1970, the first OPEC oil embargo, the nuclear accident at Three Mile Island, and other economic and financial reasons. These circumstances compelled least cost integrated resource planning that included a greater emphasis on DSM in addition to supply-side resources. In the 1990s, however, fuel costs and capacity costs decreased. Electric companies began to prepare for the potential deregulation of the retail electric industry, resulting in a diminished emphasis on DSM. Now, the pendulum has swung back. Fuel costs are increasing, interest in deregulation has waned, and the need for additional base load generation is on the horizon. The Commission believes that a renewed focus on DSM by both utilities and consumers can assist in reducing costs and protecting the environment. Thus, the Commission believes that there should be an increased focus on DSM and expects to receive more specific information regarding DSM efforts in future IRP proceedings.

The Commission finds the information discussed here valuable to its analysis in this proceeding. The Commission, however, cannot direct that a specific DSM program be implemented by a utility, or even order any substantive change in a utility's operations, as part of the IRP process. State ex rel. Utilities Commission v. North Carolina Electric. Membership Corp., 105 N.C. App. 136, 412 S.E.2d 166 (1992). That decision held as follows: "the least-cost planning proceeding should bear a much closer resemblance to a legislative hearing, wherein a legislative committee gathers facts and opinions so that informed decisions can be made at a later time." Id. at 144, 412 S.E.2d at 170. The Commission uses the information gleaned from the IRP process in the analysis required by G.S. 62-110.1(c) when acting upon a petition for the construction of a facility for the generation of electricity. As discussed above, both PEC and Duke have announced that they have instituted "reinvigorated" cost/benefit analyses of DSM options in the past year, after the 2005 annual reports were filed. Duke and PEC are expected to provide these cost/benefit analyses as part of any future application for a certificate of public convenience and necessity for construction of a generating facility. The Commission further directs the utilities to cooperate with the Public Staff and other intervenors in any of their efforts to investigate, review, and analyze these and similar analyses upon request. These requirements by the Commission are consistent with the Commission's obligations under G.S. 62-110.1 and G.S. 62-2(3a). Also, beginning with the 2006 annual reports, the utilities are directed to include a section in their reports containing a comprehensive analysis of their DSM plans, activities, and relevant cost/benefit information. If such information is not included in the 2006 plans when filed, the plans shall be supplemented with the information within 60 days.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is contained in the testimony of the public witnesses, the testimony of the PEC panel, the testimony of Duke witness Hager, the testimony of DNCP witness Koogler, the testimony of NCEMC witness Beam, the testimony of CIGFUR witness Phillips, the testimony and exhibits of NCWARN witnesses Blackburn, Konove and Ravetto, the testimony and exhibits of ED-SELC witness Prindle, and the testimony and exhibits of NCSEA witnesses Edgar, Tiller, and Parker.

Many of the public witnesses testified on the potential for cost-effective energy efficiency and conservation measures. Some suggested that the State provide low interest loans to people who want to pay for residential energy management systems. Some suggested using compact fluorescent bulbs, eliminating the clothes dryer, or providing tax credits for retrofitting and tightening building codes. In general, the public witnesses overwhelmingly endorsed potential energy efficiency and renewables as an alternative to building more generating plants, in particular more nuclear power plants. A number of public witnesses stated that the Commission should make a policy decision not to authorize the construction of any nuclear or fossil-fired generating plants in the future, because such a decision would limit the availability of electric power and would give customers a strong incentive to conserve. The Commission also received numerous letters from North Carolina citizens urging the use of potential energy efficiency and conservation to offset the need for building additional power plants.

While many of the public witnesses testified that the potential opportunities for cost-effective energy efficiency and conservation measures are extremely large, fewer of these witnesses addressed the degree to which such measures can effectively reduce consumption.

Duke witness Hager explained that Duke had engaged a consultant to identify potential DSM options for analysis in its 2005 annual plan. The consultant, Quantec, identified potential energy efficiency programs by class and by cost ranging from less than 3 cents/kWh to more than 10 cents/kWh. On that basis, Duke listed in its annual plan 715,927 MWh in potential total annual reduction from new DSM energy efficiency programs. However, there is still the question of how much of that potential is cost-effective. Ms. Hager looked to the workgroup to help answer that question.

The PEC panel also testified that, earlier this year, it started to reassess the potential for cost-effective DSM and renewable options. PEC is presently evaluating a wide array of options for all customer classes. Some options mentioned by the panel were a new load control program for residential water heating, more comprehensive energy audits, duct-sealing, and incentives for higher efficiency home and building construction. When their assessment is complete, PEC will proceed to develop more specific proposals and seek the necessary regulatory approvals, according to the PEC panel.

DNCP witness Koogler testified that DNCP offers customer education programs relating to DSM; however, tariff-based DSM, under which customers are charged higher rates for usage in peak periods, is a more effective method of reducing customer demand. He stated that customers are in the best position to decide when to purchase electric energy and how much to purchase, and tariff-based DSM programs that provide accurate price signals will enable customers to make more educated energy purchase decisions. Mr. Koogler further testified that many DSM education programs formerly provided by utilities are now available from government agencies, in the form of tax benefits for energy-conserving activities and energy efficiency standards for household equipment and appliances.

NCEMC witness Beam testified that there were significant untapped sources for energy conservation and efficiency. He contended that there are two main reasons why customers often fail to take advantage of opportunities for conserving energy. One is lack of information; many customers are not aware of the conservation opportunities available to them. The other is cost; some energy efficiency measures never produce enough savings to pay back the original costs and, in other cases, customers conclude that the savings are not enough to justify the expense or effort required.

CIGFUR witness Phillips testified that it is reasonable for utilities to educate their customers about the benefits of energy efficiency, but in his judgment it is not necessary to provide financial incentives for customers.

CUCA witness O'Donnell testified in favor of a thorough examination of all the costs and benefits associated with DSM and energy efficiency programs. He also asserted that PEC and Duke should offer a demand response rate similar to those offered by North Carolina cooperatives and municipalities. A coincident peak rate design provides an incentive to large users of electricity to curb their peak usage of electricity at the time of the system's electric peak. Taking a large load off the electric system at system peak can create savings for the utility that may avoid the need for future generation to meet peak demands. Manufacturers who install peak shaving generation typically recover the cost in approximately four years.

ED/SELC witness Prindle testified that "energy efficiency resources are available in substantial quantities at levelized costs lower than those of standard central-station new power plant technologies," such that a utility can defer or eliminate the need for new generation resources. He indicated that North Carolina could increase its energy efficiency spending and savings. The average state spending per capita on utility-sector programs is $4.93; North Carolina spends $0.44. The average annual state spending as a percentage of utility revenues is 0.54%; North Carolina spends just 0.04%. The average annual energy savings as a percentage of electricity sales is 2.1%; for North Carolina, the savings are 0.01%. Mr. Prindle recommended that the Commission pursue a deliberate, analytical path to determine what increased level of spending is appropriate.

Mr. Prindle also described numerous programs in different program categories, ranging from commercial new construction to residential lighting contained in ACEEE's America's Best report. The 2005 annual plans indicate that their current programs are only offered in a few of these categories. Mr. Prindle recommended that the utilities and the Commission consider all of the program categories in developing a new suite of energy efficiency programs. This consideration should include the basic technical and economic research needed to identify a full range of energy efficiency potential in end-use markets, program designs aimed at obtaining the maximum efficiency gains, and cost recovery and incentive structures. Advanced Energy could administer some of these programs.

Mr. Prindle testified that North Carolina could achieve a greater degree of energy efficiency by substantially increasing the number and scale of energy conservation programs available to customers. He stated that a "market transformation" model for energy efficiency programs has emerged in the last ten years. Market transformation takes a broader, longer-term view and works with the whole market to condition it toward energy efficient products. He stated that a market transformation approach is often more effective than offering large financial incentives to induce customers to adopt energy conservation measures. Mr. Prindle also discussed the tests used for evaluating DSM programs and determining which programs should be offered. Among these tests, he expressed support for use of the TRC test.

NCSEA witness Edgar testified about the tests for evaluating and selecting DSM programs, expressing support for the TRC, Societal Cost, and Utility Cost tests and identifying problems with the RIM test. He stated that if energy consumption is to be effectively reduced, the State must move beyond the earlier types of energy efficiency programs, which relied heavily on providing information to customers and offering customers financial incentives. Instead, there is a need to make use of more modem programs that focus on market transformation, working with energy use decision-makers such as architects and builders, and preventing the "lost opportunities" that occur when inefficient equipment is installed at the time a building is built or remodeled or when old equipment fails and must be replaced.

NCSEA witness Tiller recommended a comprehensive study of energy efficiency in this State because of the current lack of specific North Carolina specific data. Mr. Tiller listed areas in construction where efficiency improvements could be made: insulation, window and door treatments, air sealing and duct sealing, heating, ventilation, and air conditioning measures, hot water measures, lighting measures, and appliance and equipment measures. If efficiency improvements were made in these areas, Mr. Tiller estimated that 15,500 million kWh per year for the State could be saved. The building code as it presently exists does not reflect maximum cost-effective efficiency. Mr. Tiller opined that properly targeted utility rebate programs designed to increase the cost-efficiency of homes would have saved possibly millions of dollars in the past decade. Mr. Tiller also provided a comprehensive list of state entities involved in promoting energy efficiency.

NCSEA witness Parker testified that customer education plays a very important role in increasing and sustaining energy efficiency. He stated that one reason why customers choose not to implement an energy conservation measure is financial risk; thus, financial incentives are sometimes necessary in order to make an energy conservation system attractive to an end user.

NCWARN witness Blackburn testified that, if the total potential savings that are cost-effective could be realized, electricity demand would be reduced by some 34 billion kWh in 2015 and utilities would not need to build any additional generation. On the average, potential reductions of energy use of 30% can be found in existing buildings and 50% in new buildings. Furthermore, if every residence and commercial building in North Carolina were retrofitted to be energy efficient and if all new construction was as energy efficient as the best existing examples, there would be more conservation achieved than the proposed additional generating capacity for PEC and Duke combined. However, Dr. Blackburn was unsure whether this could be accomplished in less than a decade.

To provide an example of buildings in North Carolina that were designed with energy efficiency as a goal, Dr. Blackburn cited the Durant Middle School in Wake County, built in the 1990s, and the Rural Advancement Foundation-USA Building in Pittsboro. The Durant Middle School relies heavily on daylighting, saves money on standard lighting and air-conditioning, and consumes 27,500 BTUs per square foot per year as compared with ordinary school energy consumption of 70,000 BTUs per square foot per year. The added cost of $115,000 for construction was repaid in less than two years. The Rural Advancement Foundation-USA building uses about 30,000 BTUs per square foot per year as compared with the ordinary office building consumption of 70,000 BTUs or more per year.

If all of Dr. Blackburn's recommended actions were taken by state and local government, the construction industry, utilities, and nonprofits, he estimated that the energy-efficient potential savings would be 11-12 billon kWh per year by 2015. He testified that the extent to which the potential savings in this area can actually be realized depends very much on the vigor with which these opportunities are pursued by utilities, builders, government, and other interested parties through customer education, incentives, and, when appropriate, mandates such as building codes. Dr. Blackburn stated that one reason why energy conservation measures are not adopted more widely is lack of information among developers and homebuyers. In addition, developers and builders, who do not have to pay residential electric bills, are biased toward the lowest initial cost, and homeowners may be reluctant to invest in energy-saving measures if they anticipate selling in the near future. Dr. Blackburn also recommended a study of energy efficiency potential in North Carolina.

NCWARN witness Konove testified regarding "green building." Green building involves design and construction practices that minimize or eliminate harmful impacts on both the environment and the occupants. It consists of five categories: (1) sustainable community and site planning, (2) energy efficiency and renewable energy, (3) safeguarding water and water efficiency, (4) indoor environmental quality, and (5) materials. Homes can be built affordably or at the high-end customer level using green building.

Mr. Konove described the incentives available to builders for building green homes. Ryland Homes has worked with Advanced Energy and found that its warranty costs have decreased since incorporating better energy efficient systems. Green building provides a market niche that sets green builders apart from the competition. Mr. Konove mentioned a sealed crawl space business in

Chatham County and a construction waste recycling business as addressing the needs of green building. Furthermore, Mr. Konove testified, green building will likely be the norm in ten years.

Mr. Konove also testified about the Energy Star Homes Program, a national voluntary effort by builders to build at least 30% above existing code. Energy Star is not a green building program, but it is often a component of a green building programs. Energy Star Homes are beginning to get recognition in North Carolina, with the number of Energy Star homes doubling here in one year's time. Mr. Konove also mentioned several green building programs and builders in his testimony.

NCWARN witness Ravetto also testified about green building design and, specifically, the Leadership in Energy and Environmental Design (LEED) rating system. She explained that energy conservation in buildings includes the appropriate selection of glazing and positioning the building to maximize the conservation. She also described daylighting, the controlled use of natural lighting to displace artificial lighting. According to Ms. Ravetto, a daylighting design can save up to 75% of the energy used for electric lighting in a building. The LEED rating system is a green building rating system that is a voluntary, consensus-based national standard for developing high-performance, sustainable buildings. Owners are beginning to seek LEED certified buildings. Ms. Ravetto further testified that the average premium for green buildings compared to conventional designs is "slightly less" than 2% or three to five dollars per square foot. This cost is due to the increase in the time necessary to integrate sustainable building practices into projects.

The Attorney General's August 11, 2006 brief stated that the overwhelming evidence from the testimony at the three public witness hearings was that consumers wish to support energy conservation measures, as opposed to paying increased rates to build new coal and nuclear plants, and that, although Dr. Wright did not attend the public hearings or read the transcripts, he derided this outpouring of consumer support for DSM as unrepresentative of consumers' views. According to Dr. Wright, supporters of nuclear and coal plants are less likely to come to public hearings and voice their support. The Attorney General argued that the purpose of the Commission's public hearings is to gather information from consumers for use in the Commission's decision-making process. The Commission should not speculate on what was not stated by consumers who did not attend the public hearings.

The Attorney General noted that the Commission's rules require that DSM be a part of the companies' long-range planning in the annual IRP docket and that a thorough consideration of DSM options is required in order to meet the public convenience and necessity standard in an application for a certificate to construct a new generating plant. The Attorney General asserted that there are substantial costs and risks in building baseload plants. According to the Attorney General, captive retail ratepayers should not be required to shoulder those costs and risks until all viable DSM options have been presented and fully explored.

Based on the foregoing, it is apparent to the Commission that new opportunities for improved DSM programs are available, particularly given the recent history of DSM not being aggressively promoted. Consumers are becoming more aware of the costs of energy and are demanding additional choices that can assist them in reducing their energy consumption and costs. The Commission is also aware of national efforts to promote energy efficiency through new and existing DSM programs. While utilities have maintained limited DSM programs, the future will require a broader menu of DSM programs that provide energy reduction and efficiency opportunities at a reasonable cost.

The Commission finds that there are many such opportunities available. All of the utilities described such opportunities, from customer education to an increase in dynamic pricing signals to ratepayers. Furthermore, NCSEA, ED/SELC, and NCWARN gave specific examples of programs that were apparently both cost-effective and successful at reducing energy use and consumption. According to the testimony, a tightening of building codes, better and more energy efficient construction of residences and other buildings, and greater collaboration among utilities, builders, and industry could increase energy efficiency in this State immensely. Because the Energy Star programs have such a proven track record, a broader use of those programs could also reduce energy consumption and demand.

The Commission finds, however, that, given the information that is available today, it is not possible to calculate precisely the degree to which DSM programs can effectively reduce energy consumption at this time. In almost every case, energy conservation requires a decision by a customer to sign up for a DSM program, to purchase energy-efficient equipment, or to shift the customer's electric usage patterns. Customers arrive at these decisions in a gradual manner, and sometimes the customer chooses not to make use of a conservation opportunity. Consequently, the total energy conservation that can be achieved in a given period of time is less than the total available opportunities for conservation, but it cannot be calculated with precision.

Several witnesses called for a statewide study of energy efficiency to inform the parties on the extent and effectiveness of the current DSM program mix offered by the utilities and the availability and effectiveness of new program offerings. However, for the Commission to order such a study, the goals, scope, timeframe, and funding of it would need to be established. Those matters are presently beyond the scope of this docket. Moreover, it appears that both Duke and PEC have proceeded with their own studies concerning potential DSM. The Commission urges them to continue their revitalized evaluations and encourages the Public Staff to carefully monitor such studies.

Customer education is of great importance in any effort to promote energy conservation. Customers cannot take advantage of conservation programs of which they are unaware. Even when a customer is aware of a program's existence, education is necessary in order to bring the program's benefits to the customer's attention and persuade the customer to take part in the program. In some instances, a customer may be inclined not to participate in a program because of the inconvenience involved or because of the upfront investment required; in these circumstances, a financial incentive may be effective in inducing the customer to participate. However, financial incentives must be examined with great care. If a conservation program saves money for a utility and its ratepayers by reducing demand and thereby delaying or eliminating the need for a new generating facility, but the financial incentives paid out to program participants exceed the savings realized, the benefit of the program is lost. In the last analysis, the amount to be expended for customer education and the amount to be offered in financial incentives to customers must be carefully reviewed in the process of designing any new conservation program or modifying any existing program.

The Commission finds Duke's testimony regarding Cinergy's successes with the collaborative process among stakeholders in Ohio and Kentucky to be interesting. Such a collaborative process should be pursued in North Carolina, either with the utilities individually or within the workgroup established in this docket. The evidence at the hearing and the considerations discussed above have persuaded the Commission that a collaborative process would be a useful forum for productive discussions on the opportunities for energy efficiency.

Finally, the Commission is unable to agree with the public witnesses who proposed the adoption of a blanket policy against the construction of any new nuclear or fossil-fired plants. The population of North Carolina is growing rapidly and customer demand for power appears to be likewise increasing. While the Commission is supportive of cost-effective energy efficiency and renewable energy resources, we are not, at this time, prepared to conclude that such resources should be treated as the only appropriately available alternatives. Thus, a policy against building any nuclear or fossil-fired plants may leave the State's utilities without sufficient generation to meet demand. Utilities would seek to meet the shortfall by purchasing power from utilities in other states. Using power generated in other states in place of power generated in North Carolina would not result in any major reduction in electric usage or in any meaningful environmental benefits and would have at least one serious adverse effect. During periods of peak consumption, the state's utilities might have to pay extremely high rates to purchase power from other utilities; in some cases, they may be unable to import sufficient power at all because of the limitations of the transmission system or for other reasons. Consequently, a policy prohibiting the construction of all nuclear and fossil-fired plants may create risks of both excessive electric rates and unreliable service. Such a policy would contravene G.S. 62-2(a)(3), which provides that a primary purpose of utility regulation is "[t]o promote adequate, reliable and economical utility service to all of the citizens and residents of the State." Such a policy cannot appropriately be adopted by this Commission. However, the Commission's refusal to adopt a blanket prohibition on the construction of new nuclear or fossil-fired units should not be understood as an expression of support for any particular proposed facility. Instead, the appropriateness of such facilities, if any, must and will be determined in individual certification proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding is contained in the testimony and exhibits of witness Wright on behalf of PEC, Duke, and DNCP, the testimony of PEC panel, the testimony of DNCP witness Koogler, the testimony of NCEMC witness Beam, the testimony of CIGFUR witness Phillips, the testimony of CUCA witness O'Donnell, the testimony and exhibits of NCSEA witnesses Edgar and Tiller, and the testimony and exhibits of NCWARN witness Blackburn.

PEC, Duke, and DNCP witness Wright testified that regulators have employed a number of cost recovery and incentive mechanisms with respect to implementing DSM. He explained that several issues face regulators in developing any cost recovery program. One of those issues is how to recover the revenues "lost" to the utility when it reduces its sale of kWhs. Without recovery of these revenues and profits, a utility would not have an incentive to invest in DSM programs. A second issue is the timing of DSM cost recovery, either through a rate case or some other regulatory mechanism. The third issue is how and whether an incentive for a DSM program is tied to performance of that program or to the overall level of DSM investment.

Dr. Wright listed the various types of DSM cost recovery options: a periodic cost recovery mechanism, also called a rider; rate case recovery of costs based on actual deferred DSM expenses recovered within a recovery period of several years and a true up mechanism at the next rate case; rate case recovery of actual DSM costs through rate basing of some actual deferred costs and recovery of these actual costs over several years; and direct charging of costs to participants, which may or may not be periodically adjusted or adjusted at rate cases.

Dr. Wright also listed potential DSM incentive mechanisms: recovery of lost sales or lost margins through a tracker mechanism; a return on equity based incentive for rate-based DSM options; and a sharing of the savings or net dollar benefit of a DSM program.

Dr. Wright recounted this Commission's methods for recovery of DSM costs and incentives to invest in DSM. In the first IRP Order, Docket No. E-100, Sub 58, the Commission allowed utilities to begin accumulating in a deferred account the costs associated with the IRP, including a return, to be recovered at some future date and after review of cost proposals put forth by the utilities. In the next IRP Order, Docket No. E-100, Sub 64, the Commission indicated that DSM costs were being deferred to be recovered in the next general rate case. Also, in Docket No. E-7, Sub 487, the Commission allowed for recovery of proven lost revenues net of any "found" revenues.

Dr. Wright emphasized that utilities should have a timely recovery of all costs associated with energy efficiency, DSM, and renewable energy programs, and he expressed his preference for a rider similar to the fuel adjustment rider. Such a rider would eliminate any disincentive for reducing sales and would allow for the timely recovery of costs. He did not know whether this would be possible in North Carolina without legislation. Dr. Wright did not agree that such a rider would be "single issue ratemaking." As for the components of his proposed rider, Dr. Wright stated that he would include the direct costs, including administrative costs that the companies paid, incentives and lost revenues, minus any gains in revenue. He indicated that he might also support a policy decision to include a bonus to the utility to promote DSM aggressively.

PEC witness Williams testified that PEC agreed with Dr. Wright's conclusion that a periodic cost recovery tracking mechanism is the most appropriate method for the recovery of costs associated with DSM, and Mr. Williams suggested that this could take the form of a rate rider for recovery of all costs concurrent with the implementation of the DSM program. The components of this mechanism should include a return on capital investment, operating and maintenance expenses, including administrative expenses, program costs, and incentives paid, if any. Mr. Williams also testified that it should include an incentive or reward to encourage DSM accomplishments. Deferring recovery of costs to a rate case does not allow for timely recovery, in Mr. Williams' opinion.

DNCP witness Koogler testified that DNCP does not propose any new funding mechanisms, but instead believes that dynamic-pricing and other time-differentiated tariff options effectively fund DSM. Dynamic pricing does not impose any additional financial burdens on customers, while reducing demand for electrical generation. Mr. Koogler further testified that he generally agreed with CIGFUR witness Phillips that the costs of DSM initiatives and the collection of these costs through customers' rates, coupled with recovery of lost revenues should be such that no class of customers would benefit at the expense of another. He agreed with PEC that the utilities should be able to recover all related costs in a timely manner, recover lost revenues, and earn an incentive return on its investment.

NCEMC witness Beam testified that any incentives provided by a utility to encourage DSM to the customer should be no more than the savings produced by the program. Furthermore, he testified that such incentives should not be at the expense of any particular class of customers to the benefit of another, be it taxpayers or ratepayers.

CIGFUR witness Phillips testified that a discussion of funding mechanisms for DSM programs does not belong in an IRP proceeding. He further indicated that utilities should not perform a government function such as taxing some ratepayers and providing payments to others. He advocated cost-based rates to encourage DSM. Mr. Phillips considered Dr. Wright's suggestion of a rider to fund DSM programs as "single issue ratemaking." Imposing such a rider in this proceeding could result in unnecessary rate increases that are neither sought by the utilities nor justified in a rate case. In sum, Mr. Phillips opposed any rate increase outside of a rate case.

CUCA witness O'Donnell testified that, while CUCA supports DSM and energy efficiency efforts, it believes that such programs should be cost-effective, free from subsidization and equitable. He was opposed to a public benefit fund because of the financial hardship to manufacturers who need to realize a benefit in the short-term. Mr. O'Donnell was also opposed to the rate rider recommended by Dr. Wright and the PEC panel. He stated that the Commission should review DSM costs in a rate case and then design rates accordingly. General rates incorporate all kinds of costs and revenues which change from year to year. CUCA argued that singling out environmental program costs for deferral is not fair to ratepayers because it ignores all other changes in costs and revenues and may result in a windfall to the utilities. If the implementation of environmental programs has a materially adverse effect on a utility's earnings, the utility can always initiate a general rate proceeding before the Commission, which will allow both the utility and its ratepayers to look at all of the utility's revenues and expenses.

NCSEA witness Edgar testified that there have been three basic approaches to funding energy efficiency programs: (1) a tax on utility customers to create a public benefit fund, (2) a charge to utility customers as part of the utility's cost of providing service to fund programs administered either by the utility or by a third-party administrator, and (3) a combination of the two approaches above. He described Focus on Energy, an energy efficiency initiative in Wisconsin. He noted that the Wisconsin legislature recently enacted Act 141, which moved the funding for this program from a tax on utility customers to a charge to be levied as a cost of doing business for the utilities. The utilities will collectively issue a bid to select a third party, non-utility entity as a program administrator. He acknowledged that there are many pros and cons with these approaches, but concluded that the entity administering the program should have a clear incentive and motivation to succeed. Mr. Edgar also testified that funding for the energy efficiency programs could come from a greater partnership with marketers who provide high-energy efficiency products. Two private sources of funding are energy service companies and financial institutions.

NCSEA witness Tiller testified that efficiency improvements should be administered by a statewide organization. He listed a wide array of potential agencies that may be qualified to do this, including but not limited to the State Energy Office and Advanced Energy Corporation. He further recommended a funding mechanism similar to the Focus on Energy program in Wisconsin.

NCWARN witness Dr. Blackburn testified that financial assistance must be provided more generously to spur investments in energy efficiency. He mentioned tax credits and low interest loans, but he indicated that a public benefit fund is the best financing mechanism. Even though Dr. Blackburn testified that there are many potential cost-effective energy efficiency programs, a public benefit fund would help to overcome the lack of knowledge about energy efficiency.

The Commission has carefully considered the testimony of the witnesses in this proceeding regarding funding and incentive mechanisms for DSM programs. In considering this issue, the Commission has revisited its previous IRP orders regarding incentive mechanisms and the development of the DSM cost recovery from the early 1990s. The Commission first explicitly considered implementation of appropriate rewards to utilities for successful efficiency and conservation measures, pursuant to G.S. 62-2(3a), in Docket No. E-100, Sub 58. During that proceeding, the Public Staff entered into stipulations with Duke, CP&L (now PEC), and North Carolina Power (now DNCP) essentially recommending that the Commission find ways to reward the utilities for successful implementation of their IRP plans. In its Order Adopting Least Cost Integrated Resource Plans, issued May 17, 1990, the Commission addressed the issue of rewards by stating:

> The Commission believes this to be an issue on which there is a general consensus by all parties that procedures must be developed to encourage positive least cost integrated resource planning accomplishments. ... [T]he Commission finds that it is appropriate for the utilities to initiate deferral accounting procedures for the purpose of accumulating and deferring costs associated with implementation of Commission approved least cost integrated resource plans, including a return at each utility's last approved overall rate of return. The Commission concludes that each utility should be required to file its proposed plan for recovery of these costs with its next short-term action plan in this docket. The companies' filings should address the kinds of costs that they are proposing to accumulate and defer for future inclusion in rate case proceedings.
>
> ...

In its Order Adopting Least Cost Integrated Resource Plans issued on June 29, 1993, in Docket No. E-100, Sub 64, the Commission noted developments in the area of DSM cost recovery and incentive mechanisms since the Sub 58 Order. First, the Commission recounted that PEC, Duke, and DNCP had filed proposed plans for the recovery of DSM costs and incentives in May 1991, and the Public Staff and other parties filed comments on those proposals in August 1991. Furthermore, on September 9, 1991, a stipulation between Duke and the Public Staff was filed and approved in Duke's then-ongoing general rate case proceeding, Docket No. E-7, Sub 487, allowing Duke to defer certain DSM program costs beyond those currently reflected in rates, including explicit incentives, rebates, and advertising costs, for future rate recovery. The stipulation also provided that Duke could seek to recover lost revenues, but only to the extent that it satisfied the burden of proof regarding such lost revenues and offset such lost revenues with "found" revenues attributable to load factor improvement programs. Finally, the stipulation provided that at the time rewards were recognized pursuant to G.S. 62-2(3a), they would be added to the deferred balance.

Next, on October 20, 1992, the Public Staff and Duke entered into a stipulation in E-100, Sub 64, that provided for a shared savings reward mechanism for DSM programs that decreased utility bills. The reward would be based on demonstrated kW and kWh savings, and would equal 15% of the North Carolina retail net savings from the program in a given calendar year. However, the reward would be limited to 0.5% of Duke's North Carolina retail revenues recorded in the calendar year for which the reward was claimed.

On October 20 and October 30, 1992, stipulations between the Public Staff and DNCP and the Public Staff and PEC were filed with the Commission in Docket No. E-100, Sub 64. These cost recovery and reward mechanism stipulations were virtually identical to the stipulations between the Public Staff and Duke, with the exception of the number of years of savings used to calculate rewards.

In its Sub 64 Order, the Commission approved the stipulations entered into by the Public Staff, on one hand, and Duke, PEC, and DNCP, on the other. In conjunction with this approval, the Commission stated:

> The Commission concludes that special ratemaking treatment of DSM currently is appropriate to encourage utilities to invest aggressively in DSM resources. This special treatment includes three key elements: (1) the recovery of certain incurred costs associated with operating DSM programs; (2) the recovery of "lost" revenues resulting from energy efficiency programs; and (3) an additional financial incentive, or reward, for exemplary DSM accomplishments.
>
> The deferred account mechanism ... contemplates the potential inclusion of all three of the elements identified above. The use of deferred accounting for all three of the special ratemaking elements is appropriate. The purpose of the stipulated deferred accounting is to attempt to remove any perceived disincentive by utilities to the implementation of DSM programs.
>
> [T]he Commission cannot conclude at this time, as advocated by the Public Staff, that the reward element should be allowed exclusively as a "jump start" mechanism and should be discontinued as soon as is reasonably practicable. Nevertheless, the need for continuation of the reward mechanism is an issue that the parties may address in future LCIRP proceedings. The Public Staff, and any other party for that matter, always has the right to petition the Commission to prospectively modify or delete any aspect of the reward mechanism.

The Commission revisited the topic of deferral accounting for DSM cost recovery and additional incentives in its Order Adopting Least Cost Integrated Resource Plans issued in Docket No. E-100, Sub 75, on February 20, 1996. The Commission's Order noted that the Public Staff had proposed that deferral accounting for DSM costs be discontinued because (1) the need to spur initial development of DSM had passed and (2) increasing use of the RIM test to evaluate DSM programs resulted in programs for which an incentive was not needed. The Public Staff also noted that, while PEC had not implemented deferral accounting for DSM costs and while DNCP's deferral balance was only $175,000, Duke had deferred $40 million in costs, and if allowed to continue, could defer more than $140 million by the year 2005. The Commission went on to state that Duke had filed a response to the Public Staff's proposal, noting that Duke had reached a stipulation with the Public Staff during the proceeding to restrict its future deferral accounting to certain programs, cap its DSM deferral account at $75 million, and cease accruing the DSM reward element as of December 31, 1995.

Since the Commission's Order in Docket No. E-100, Sub 75, Duke, PEC, and DNCP have each taken different paths with regard to DSM cost recovery and additional incentives. Duke has continued to defer its DSM costs, net of revenue collections, subject to the stipulation entered into in Docket No. E-100, Sub 75. DNCP's deferral account was terminated as part of the resolution of its 2005 general rate case proceeding, Docket No. E-22, Sub 412. As of September 2004, DNCP's accumulated deferral was a credit owed to ratepayers in excess of $8 million, including interest. The credit due to ratepayers was amortized as a credit to rates over a three-year period in DNCP's recent rate case. To the knowledge of the Commission, PEC has never initiated deferral accounting for DSM costs or additional incentives.

A review of the Commission's past actions with regard to DSM cost recovery and additional incentives shows that the Commission properly implemented the policy expressed in G.S. 62-2(3a) to consider appropriate rewards to utilities for successful efficiency and conservation measures that reduce utility bills. The Commission established special ratemaking treatment including deferral accounting, for three components of DSM costs and incentives: incurred costs, lost revenues, and a shared savings reward. The Commission has altered these allowances only twice: first, in agreeing to the limitation of Duke's deferral accounting when it appeared that Duke's deferral account could become unreasonably large and, second, approving the termination of DNCP's deferral account in the 2005 general rate case when it became evident that a relatively substantial amount of money was owed to DNCP's North Carolina retail ratepayers. However, as noted in several of the Commission's IRP proceedings held since Docket No. E-100, Sub 75, the utilities' emphasis on DSM has lessened over time, due to several factors unrelated to cost recovery. To the extent the utilities have established deferral accounts, these accounts reflect this lessening of emphasis and expenditures.

The special ratemaking treatment for DSM established by the Commission in the early 1990s was appropriate for the conditions in North Carolina at that time, including the condition of the market for DSM products and services, the posture of the utilities toward DSM, the customers' understanding of the benefits and costs of DSM, and the regulatory environment. All of these factors influenced the Commission's approach to the implementation of DSM initiatives, and the funding and ratemaking treatment of DSM reflected the specific circumstances of the early 1990s.

The Commission believes that its approach to the funding and ratemaking treatment of costs and additional incentives in this era of renewed emphasis on DSM must reflect the present circumstances. As the testimony showed, many factors have changed since the early 1990s. The Commission believes that the ratemaking treatment and the design of additional incentives must be based on the objectives of DSM. Although progress is being made in this proceeding, the picture is not yet entirely clear. Therefore, the Commission believes that it is premature to settle on any particular funding mechanism or ratemaking treatment as a means of meeting the policy expressed in G.S. 62-2(3a). The Commission also wishes to emphasize that special ratemaking treatment could be unnecessary if DSM efforts are to be administered by an independent third party statewide. To move forward, the Commission particularly looks to the collaborative process to facilitate the development of an approach to DSM in the appropriate environment. Once the picture becomes clearer, additional steps can be taken to develop or refine any funding mechanisms and ratemaking treatment or to consider innovative funding options, such as a third party administrator of DSM efforts, to fulfill the policy expressed in G.S. 62-2(3a).

The Commission also wishes to note that it does not fully agree with the testimony of CIGFUR witness Phillips that a discussion of funding mechanisms does not belong in an IRP proceeding. As discussed herein, it is clear that the requirements and guidelines for DSM cost recovery and additional incentives have historically been addressed in this very type of proceeding. The Commission intends to stay within the bounds of applicable law and policy with regard to what actions can and cannot be appropriately taken in the context of its IRP proceedings; however, the Commission concludes that, to the extent permitted by such law, there is no better forum than an IRP proceeding for discussion of appropriate and reasonable funding mechanisms for DSM costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding is contained in the testimony and exhibits of the witnesses in this proceeding, the comments of the parties, and the utilities' annual plans.

As the Commission has stated in previous IRP dockets,

> IRP review is intended to ensure that each utility is including all the considerations required by the Commission's Rules in its planning process, that each utility is generally utilizing state-of-the-art techniques for its forecasting and planning activities, and that each utility has developed a reasonable analysis of its long-range needs for expansion of generation capacity. Also, the Commission reiterates its opinion that evaluations of individual DSM programs, certificates to construct new generating plants or transmission lines, and individual purchased power contracts should be handled in separate dockets from the IRP proceeding.

This Commission has also emphasized in several IRP proceedings that the inclusion of a DSM program or a proposed new generating station in a utility's IRP filing does not constitute approval of such individual elements, even if the utility's IRP itself is approved.

Based upon the foregoing, the Commission's review of the annual plans, the comments filed in this docket, and the entire record of this proceeding, the Commission concludes that the current IRPs are reasonable for purposes of this proceeding and should be approved.

IT IS, THEREFORE, ORDERED as follows:

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

2. That the IRPs filed by PEC, Duke, DNCP, NCEMC, and WCE in this proceeding are hereby approved as hereinabove discussed;

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

4. That future IRP filings by all utilities shall continue to include a discussion of the adequacy of the respective utility's transmission system (161 kV and above) and in addition, each utility shall include a copy of the most recently completed FERC Form 715, including all its attachments and exhibits;

5. That the utilities shall meet with the Public Staff within 30 days of the filing date of future annual reports to discuss detailed information concerning their transmission line inter-tie capabilities, transmission line loading constraints, and planned new construction and upgrades within their respective control areas for the planning period under consideration;

6. That future IRP filings by all utilities shall continue to provide a separate and updated list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and stand-by generating facilities, to the fullest extent possible and this information should include facility name, primary fuel type, and capacity and location, and should indicate which facilities are included as part of their total supply resources;

7. That future IRP filings by PEC, Duke, and DNCP shall continue to include information on levelized busbar costs for various conventional, demonstrated, and emerging generation technologies, and any claim of confidentiality under the North Carolina Public Records Act shall be set forth with specificity at the time this information is filed and shall conform to each of the conditions specified in G.S. 132-1.2 and in addition, a redacted non-confidential version of the information in question shall also be included in the annual report filings;

8. That future IRP filings shall contain the following: the identity of each wholesale entity to which the utility has committed itself to sell power during the planning horizon, the number of MWs on an annual basis for each such contract, the length of each contract, and the type of each contract (e.g., native load priority, firm);

9. That future IRP filings by PEC, Duke and DNCP shall include a section containing a comprehensive analysis of their DSM plans and activities, including relevant cost/benefit information; and

10. That, upon request, the utilities shall cooperate with the Public Staff and other intervenors in any of their efforts to investigate, review, and analyze the utilities' cost/benefit analyses of their DSM programs.

This the 31st day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr083106.01

DOCKET NO. E-100, SUB 105

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Revise Commission	)	
Rule R8-62, Certificates of Environmental	)	ORDER AMENDING
Compatibility and Public Convenience and	)	RULE R8-62
Necessity for the Construction of Electric	)	
Transmission Lines in North Carolina	)	

BY THE COMMISSION: On November 30, 2005, the Commission initiated a rulemaking proceeding to amend Rule R8-62 to require an applicant seeking a certificate of environmental compatibility and public convenience and necessity for the construction of electric transmission lines in North Carolina to prefile direct testimony with the application for certification. The Commission made Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (Progress); Duke Power, a division of Duke Energy Corporation (Duke); and Virginia Electric and Power Company d/b/a Dominion North Carolina Power (Dominion) parties to the proceeding. Further, the Commission permitted other interested persons to intervene and required the parties to file comments on the proposed amendments. On January 26, 2006, the Commission allowed North Carolina Electric Membership Corporation (NCEMC) to intervene in the proceeding.

Progress and Dominion separately filed comments on the proposed amendments. Progress requested that the final rule clarify that prefiled direct testimony is not required when an applicant files for a waiver of the notice and hearing requirements pursuant to Rule R8-62(k) and G.S. 62-101(d)(1). Progress and Dominion both requested that the Commission make clear that an applicant may file supplemental direct and/or rebuttal testimony in response to prefiled expert testimony by the Public Staff and other intervenors in a contested case.

After careful consideration of the concerns raised by Progress and Dominion, the Commission concludes that the final rule should clarify that prefiled direct testimony is not required when an applicant files for a waiver of the notice and hearing requirements pursuant to Rule R8-62(k) and G.S. 62-101(d)(1). The Commission further concludes that deadlines for prefiling rebuttal testimony in future transmission line proceedings should be established in their respective scheduling orders.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective as of the date of this Order, Commission Rule R8-62 is hereby amended as set forth in the Appendix A attached hereto.

2. That deadlines for prefiling rebuttal testimony in future transmission line proceedings shall be established in their respective scheduling orders.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of February, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Lh022306.01

APPENDIX A

Rule R8-62 is hereby amended by adding a new section (c)(7) which reads as follows:

(c)(7) The application shall be accompanied by prefiled direct testimony incorporating and supporting the application. Provided, however, an applicant requesting a waiver of the notice and hearing requirements pursuant to Rule R8-62(k) and G.S. 62-101(d)(1) shall not be required to prefile direct testimony supporting the application unless the waiver request is subsequently denied by the Commission.

Further, Rule R8-62(j) will be rewritten as follows:

(j) Testimony and exhibits by expert witnesses shall be filed pursuant to Commission Rule R1-24(g). Absent substantial cause, the Public Staff and other intervenors shall file direct testimony and exhibits of expert witnesses no later than the deadline established for filing petitions to intervene. Non-expert witness testimony is not required to be reduced to writing or filed prior to the hearing.

DOCKET NO. P-100, SUB 133k

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Generic Docket to Address Performance Measurements and Enforcement Mechanisms	)))	ORDER GRANTING BELLSOUTH'S PETITION TO MODIFY SQM/SEEM PLAN

BY THE COMMISSION: On September 30, 2005, BellSouth Telecommunications, Inc. (BellSouth), and AT&T Communications of the Southern States, LLC (AT&T), DIECA Communications, Inc., d/b/a Covad Communications Co. (Covad), ITC^DeltaCom, Inc. (ITC), MCImetro Access Transmission Services, LLC and MCI WORLDCOM Communication, Inc. (MCI), KMC Telecom Inc. (KMC), Z-Tel Communications, Inc. (Z-Tel), and IDS Telecom, LLC (IDS) (collectively the competitive local exchange company (CLEC) Coalition) jointly filed a Motion requesting the Commission to approve a new Service Quality Measurement (SQM) Plan and Self-Effectuating Enforcement Mechanism (SEEM) Plan (a copy of which was attached to the Joint Motion). BellSouth and the CLEC Coalition noted that, upon Commission approval, the proposed SQM/SEEM Plan would supersede and replace the then-current SQM/SEEM Plan.

By Order dated October 24, 2005, the Commission granted the Joint Motion, thereby approving the proposed SQM/SEEM Plan, unless objections to the proposed SQM/SEEM Plan were filed by no later than November 7, 2005. The Commission subsequently granted a request for an extension of time to file objections, and objections were due by no later than November 14, 2005.

No objections were received, and BellSouth's new SQM/SEEM Plan was approved effective November 15, 2005. BellSouth implemented its new SQM/SEEM Plan on January 1, 2006.

On March 1, 2006, the Commission issued its *Order Concerning Changes of Law* (hereinafter, the *Change of Law Order*) in Docket No. P-55, Sub 1549. In the *Change of Law Order*, the Commission made the following relevant Findings of Fact:

> **Finding of Fact No. 8** – The Commission does not have the authority to require BellSouth to include Section 271 elements in ICAs [interconnection agreements] entered into pursuant to Section 252, nor does the Commission have the authority to set rates for such elements.
>
> **Finding of Fact No. 12** – With the Commission's approval of the new, stipulated SQM/SEEM Plan in Docket No. P-100, Sub 133k, effective November 15, 2005, the issue in this docket of removing delisted UNEs [unbundled network elements] from the SQM/SEEM Plan is moot.

No party in the change of law docket filed an objection to the Commission decisions embodied in either Finding of Fact No. 8 or Finding of Fact No. 12.

On March 31, 2006, BellSouth filed a Notice of Intent to Modify the SQM/SEEM Plan. BellSouth noted that, pursuant to Section 4.6.1 of its SEEM Plan[1], it was going to modify its SQM/SEEM Plan, effective on May 1, 2006, to implement the Commission's March 1, 2006 *Change of Law Order*. BellSouth attached a redlined version of the modified SQM/SEEM Plan to its Notice.

BellSouth commented in Footnote No. 3 of its March 31, 2006 Notice that, because the Commission determined in its *Change of Law Order* which elements had been delisted under Section 251(c)(3) of the Telecommunications Act of 1996 (the Act), there was no need for BellSouth to file the Petition described in Section 4.6.1 of the Plan.

BellSouth stated that, pursuant to SEEM Section 4.6.1, BellSouth planned to remove the following delisted elements from the SQM/SEEM Plan:

(1) UNE Line Sharing;
(2) UNE Switching;
(3) Sub-Loop Feeder;
(4) High Capacity Loops (DS1 and DS3) in unimpaired wire centers;
(5) Dark Fiber Loops (maintenance and repair metrics for the embedded base remain in the Plan until the September 2006 data month);
(6) Dedicated Transport (DS1 and DS3) in unimpaired wire centers;
(7) Dark Fiber Transport in unimpaired wire centers (maintenance and repair metrics for the embedded base remain in the Plan until the September 2006 data month);
(8) Entrance Facilities (i.e., local channels); and
(9) OCn Level Facilities.

On April 10, 2006, the Commission issued an Order allowing interested parties, including the Public Staff, to file objections to or comments on BellSouth's March 31, 2006 Notice by April 24, 2006.

Comments were filed on April 24, 2006 by Covad, DeltaCom, Inc. (DeltaCom), and Business Telecom Solutions, Inc. (BTI) (hereinafter, the Competing Local Provider (CLP) Parties), and the Public Staff. On May 1, 2006, the Commission issued its *Order Recognizing BellSouth's Notice of Intent as its Petition and Seeking Comments*.

On May 17, 2006, initial comments were filed by the CLP Parties and the Public Staff. BellSouth filed reply comments on May 30, 2006.

INITIAL COMMENTS

The CLP Parties objected to BellSouth's Notice of Intent to Modify the SQM/SEEM Plan filed with the Commission on March 31, 2006, for the reasons set forth on pages 102 through 109 of the Commission's *Change of Law Order*, regarding removal of elements from the SEEM Plan. The CLP Parties asserted that the network elements delisted under Section 251(c)(3) should not be removed from the SQM/SEEM Plan to the extent such network elements are still required pursuant to Section 271. The CLP Parties maintained that the SQM/SEEM performance measurements were

[1] Section 4.6.1 of the Plan states, in relevant part, that if a change of law occurs which may relieve BellSouth of the obligation to provision a particular UNE or UNE combination, BellSouth shall Petition the Commission within 30 days if it seeks to cease reporting data or paying remedies in accordance with the change of law.

instituted to confirm BellSouth's compliance with its Section 271 obligations. The CLP Parties argued that, when switching, loop, and transport network elements are no longer available under Section 251, BellSouth still must provide meaningful, nondiscriminatory access to such network elements pursuant to the Section 271 competitive checklist. The CLP Parties asserted that it is not compliance with Section 251 obligations that SQM/SEEM Plans are designed to measure, rather it is compliance with Section 271 obligations – including the provision of unbundled elements required even after a finding of no impairment under Section 251. The CLP Parties opined that the Section 271 checklist items that must be unbundled should remain subject to the SQM/SEEM Plan.

The CLP Parties noted that the Federal Communications Commission (FCC) ruled in the *Triennial Review Order* (*TRO)* that the Bell Operating Companies' (BOCs') unbundling obligations under Section 271 exist *independently* of the unbundling obligations the FCC establishes for all incumbent local exchange companies (ILECs) under Section 251, since to find otherwise would mean that Section 271 has no legal import whatsoever. The CLP Parties maintained that BellSouth wishes that an FCC decision to eliminate unbundling of a network element under Section 251(c) would automatically translate into eliminating Section 271 unbundling for that element, but that is not the law. The CLP Parties asserted that the FCC's determination that Section 271 establishes a separate unbundling obligation was affirmed by the D.C. Circuit in *USTA II*. The CLP Parties noted that BellSouth petitioned the FCC to remove the Section 271 unbundling requirement – through forbearance – with respect to all network elements that were "declassified" by the FCC, but the FCC did not grant BellSouth's petition. The CLP Parties stated that, thus, except for the four elements specified in the FCC's forbearance ruling, all other unbundling requirements contained in Section 271 remain in effect.

The CLP Parties asserted that Sections 271(c)(2)(B)(iv) through (vi) of the Act require the BOCs to provide local loops, transport, and switching. Further, the CLP Parties noted that the FCC has found that the BOC's obligation to make Section 271 checklist items available to CLPs is *independent* of the obligation to provide access to network elements under Section 251. The CLP Parties noted that the FCC held in Paragraph 659 of the *TRO* that:

> [I]f, for example, pursuant to section 251, competitive entrants are found not to be 'impaired' without access to unbundled switching at TELRIC [total element, long-run incremental cost] rates, the question becomes whether BOCs are required to provide unbundled switching at TELRIC rates pursuant to section 271(c)(2)(B)(vi). In order to read the provision so as not to create a conflict, we conclude that section 271 requires BOCs to provide unbundled access to elements not required to be unbundled under section 251 but does not require TELRIC pricing.

The CLP Parties noted that the D.C. Circuit in *USTA II* considered and affirmed the FCC's treatment of these issues in the *TRO*. The CLP Parties stated that, thus, BellSouth must make loops, transport, and switching available as checklist items even after the FCC finds those network elements are no longer available under the standards established in Section 251.

The CLP Parties maintained that the FCC has recognized state commission authority to enforce the terms of Section 271 access post-approval. The CLP Parties stated that, while noting that Congress authorized the FCC to enforce Section 271 to ensure continued checklist compliance, the FCC's *New York Section 271 Order* specifically endorsed state commission authority to enforce commitments made by Verizon [then Bell Atlantic] to the New York Public Service Commission (PSC). The CLP Parties noted that the FCC stated that:

> Complaints involving a BOC's alleged noncompliance with specific commitments the BOC may have made to a state commission, or specific performance monitoring and enforcement mechanisms imposed by a state commission, should be directed to that state commission rather than the FCC.

The CLP Parties stated that, indeed, the FCC noted "with approval" the fact that the New York Performance Assessment Plan (PAP) "will be enforceable as a New York Commission order." The CLP Parties stated that each and every subsequent FCC order granting BOC long distance entry reached the same conclusion: state commissions are fully empowered to ensure BOC compliance with the competitive checklist after Section 271 application approval.

The CLP Parties noted that, in an FCC Order for Arizona, the FCC <u>commended</u> state commissions for all the work they performed in rendering Bell company operations and processes Section 271 compliant. The CLP Parties stated that, moreover, the FCC's Order made it clear that continuing state commission authority to enforce Bell company compliance with the requirements of Section 271 extended beyond the date of FCC Section 271 approval. The CLP Parties maintained that, indeed, in determining to grant Qwest's Arizona Section 271 application, the FCC relied explicitly on the ongoing enforcement authority of state commissions post-approval, under <u>either federal or state law</u>. Furthermore, the CLP Parties stated, the FCC took explicit note of the specific authority of state commissions to resolve carrier-to-carrier disputes under Section 271. The CLP Parties noted the FCC's statement that "section 271 does not compel us to preempt the orderly disposition of intercarrier disputes by state commissions."

The CLP Parties maintained that, for the reasons summarized in their initial comments and set forth in detail in *CompSouth's Response to BellSouth's Motion for Summary Judgment or Declaratory Ruling* and the Commission's *Change of Law Order*, the CLP Parties objected to BellSouth's Petition and requested that it be denied by the Commission.

The **<u>Public Staff</u>** stated in its initial comments that, under Sections 271(c)(2)(B)(iv) through (vi), BellSouth was required to provide access and interconnection to its network for the following as part of its "competitive checklist" in order to be eligible to provide interLATA long distance service in North Carolina:

- Local loop transmission from the central office to the customer's premises, unbundled from local switching or other services (Section 271(c)(2)(B)(iv);

- Local transport from the trunk side of a wireline local exchange carrier switch unbundled from switching or other services (Section 271(c)(2)(B)(v); and

- Local switching unbundled from transport, local loop transmission, or other services (Section 271(c)(2)(B)(vi).

The Public Staff stated that it believes that each of the delisted elements BellSouth proposes to remove from its SQM/SEEM Plan falls into one of these categories, and could be viewed as a

"Section 271 requirement" independent of whether or not it was also required to be provided under Section 251(c) of the Act.

The Public Staff noted that, in Docket No. P-55, Sub 1549, the Commission reviewed whether network elements delisted under Section 251(c)(3) should be removed from the SQM/SEEM Plan. The Public Staff commented that CompSouth argued that such elements should not be removed from the SQM/SEEM Plan to the extent they were still required pursuant to Section 271 of the Act. The Public Staff opined that this issue was not resolved squarely because the Commission concluded that the approval of the recent, jointly-filed SQM/SEEM Plan rendered the issue moot. Thus, the Public Staff noted, the Commission's *Change of Law Order* did not expressly address whether BellSouth was permitted to remove Section 271 requirements from the SQM/SEEM Plan.

The Public Staff commented that the CLP Parties referred to CompSouth's argument in Docket No. P-55, Sub 1549 in their initial comments on this matter, asserting that, although the network elements at issue here may have been delisted pursuant to Section 251 of the Act, BellSouth must still provide meaningful, nondiscriminatory access to such network elements pursuant to the Section 271 competitive checklist. The Public Staff stated that, therefore, according to the CLP Parties, those network elements should remain in the SQM/SEEM Plan.

The Public Staff stated that it agrees that BellSouth must still provide meaningful, nondiscriminatory access to such network elements pursuant to Section 271. The Public Staff asserted that the question remains, however, whether the SQM/SEEM Plan is the appropriate mechanism to measure BellSouth's performance in providing such access. The Public Staff maintained that self-enforcing penalty plans, including the North Carolina SEEM Plan, were adopted by state commissions to deter BOCs from retreating or "backsliding" in their provision of services to competitors after they received in-region, interLATA long distance authority from the FCC. The Public Staff noted that, pursuant to these plans, if BellSouth fails to provide nondiscriminatory access to Section 251 UNEs, it must pay the affected CLPs or the state monetary penalties.

The Public Staff maintained that, in this docket, BellSouth and the CLEC Coalition jointly filed the stipulated SQM/SEEM Plan on September 30, 2005. The Public Staff noted that the SQM/SEEM Plan states that it "was developed to respond to the requirements of the Communications Act of 1996 Section 251 . . . which required BellSouth to provide non-discriminatory access to Competitive Local Exchange Carriers (CLEC)." The Public Staff maintained that Section 2.1 of the SEEM Plan states that, "[i]n providing services *pursuant to the Interconnection Agreements between BellSouth and each CLEC*, BellSouth will report its performance to each CLEC in accordance with BellSouth's SQMs and pay remedies in accordance with the applicable SEEM, which are posted on the Performance Measurement Reports website."

The Public Staff opined that the Commission, however, no longer requires the elements in question to be included in interconnection agreements (ICAs) as either Section 251(c) elements or Section 271 requirements. The Public Staff asserted that Section 251(c) elements are those that the FCC has determined are necessary for CLPs to provide service and that, without access to the ILEC's network, a CLP would be impaired in its ability to do so. The Public Staff opined that since the elements that BellSouth seeks to remove have been delisted, they are no longer considered "necessary" and the CLPs are no longer impaired without access to them from BellSouth. The Public Staff maintained that, in other words, the services are competitive and the CLPs may purchase similar services from other providers through commercial agreements that may include their own penalties for performance failures.

The Public Staff stated that, additionally, the Commission determined in the *Change of Law Order* that it could not require Section 271 elements to be included in ICAs. The Public Staff maintained that the Commission noted that "enforcement of Section 271 is largely the responsibility of the FCC, with the role of the State commissions being essentially advisory in nature, most notably and explicitly when a BOC applies for interLATA long distance authority." The Public Staff argued that, thus, to the extent that the provision of these nine delisted elements to competitors represents an ongoing Section 271 obligation, but not a Section 251 obligation, it may be appropriate to continue to monitor and assess BellSouth's performance, and to penalize BellSouth for unacceptable performance. However, the Public Staff pointed out that Section 271(d)(6) seems to assign those statutory responsibilities exclusively to the FCC.

Finally, the Public Staff noted that Section 4.6.1 of the SEEM Plan provides that, "[i]f a change of law occurs which may relieve BellSouth's provisioning of a UNE or UNE combination, BellSouth shall Petition the Commission within 30 days if it seeks to cease reporting data or paying remedies in accordance with the change of law." The Public Staff asserted that it appears, then, that the parties to the stipulated SQM/SEEM Plan at least contemplated that if BellSouth were relieved of its obligation to provide certain UNEs or UNE combinations, it could petition for removal of those elements. Accordingly, the Public Staff stated that it does not object to BellSouth's removal of the delisted elements from the SQM/SEEM Plan.

REPLY COMMENTS

BellSouth stated in its reply comments that the removal of delisted elements from the SQM/SEEM Plan is a logical and straightforward application of the Commission's rulings in its March 1, 2006 *Change of Law Order*. Accordingly, BellSouth submitted that the Commission should grant BellSouth's Petition and thus allow BellSouth to remove delisted Section 251 elements from the SQM/SEEM Plan.

BellSouth noted that the Commission, in its *Change of Law Order*, correctly concluded that "it does not have the authority to require BellSouth to include Section 271 elements in ICAs entered into pursuant to Section 252, nor does the Commission have the authority to set rates for such elements." BellSouth maintained that the Commission further concluded "that BellSouth and the CLPs should be required to execute amendments to their ICAs deleting the provisions requiring BellSouth to offer the UNEs that the FCC has found are no longer required to be offered under Section 251(c) of the Act. . . ." BellSouth argued that, in short, in its *Change of Law Order*, the Commission essentially concluded that, unless otherwise agreed to, an ICA approved pursuant to Section 252 of the Act should be limited to Section 251 elements that BellSouth must provide to CLPs.

BellSouth asserted that the SQM/SEEM Plan is effectively incorporated into a CLP's ICA by virtue of an Attachment to the ICA (typically Attachment 9). BellSouth argued that, because the Commission has appropriately determined that such ICAs should not contain Section 271 elements, it logically follows that the SQM/SEEM Plan should not contain Section 271 elements.

BellSouth maintained that, accordingly, the argument made by the CLP Parties that delisted elements should remain in the SQM/SEEM Plan when such elements are required to be provided pursuant to the Section 271 checklist items must fail, because fundamentally this argument is no different than the already-rejected argument that Section 252 ICAs must contain delisted elements when those elements remain Section 271 checklist items. BellSouth stated that, in not objecting to BellSouth's removal of delisted elements from the SQM/SEEM Plan, the Public Staff essentially reached this same conclusion. BellSouth argued that, contrary to the CLP Parties' assertion in their comments, the continued unbundling of Section 271 elements is not the issue here. BellSouth maintained that it is required to offer Section 271 elements on an unbundled basis. However, BellSouth stated that, as the Public Staff noted in its comments, "since the elements that BellSouth seeks to remove have been delisted, they are no longer considered 'necessary' and the CLPs are no longer impaired without access to them from BellSouth." Further, BellSouth asserted that, as the Public Staff recognized, the enforcement of Section 271 is largely the responsibility of the FCC, with the role of the state commission being essentially advisory in nature. BellSouth argued that, accordingly, for the reasons set forth in its reply comments, as well as for the reasons set forth in BellSouth's Post-Hearing Brief in Docket No. P-55, Sub 1549 at pages 85 through 87 and as stated in the well-reasoned comments of the Public Staff, the Commission should issue an order allowing BellSouth to remove delisted elements from the SQM/SEEM Plan. BellSouth noted that, in addition to being consistent with the Commission's Findings of Fact Nos. 2 and 8 in its *Change of Law Order*, such an order would be consistent with decisions of the PSCs in Florida[1], South Carolina[2], and Alabama[3], all of which have concluded that delisted elements should be removed from the SQM/SEEM Plan. BellSouth acknowledged that, based upon its Section 271 ruling, the Georgia PSC issued a ruling requiring BellSouth to keep delisted elements in the Georgia SQM/SEEM Plan (GA Docket No. 19341-U). BellSouth stated that it has appealed the Georgia PSC's Section 271 ruling. Additionally, BellSouth maintained that, on May 15, 2006, in Docket No. 04-00381, the Tennessee Regulatory Authority (TRA) ruled the same way as the Georgia PSC had ruled on this issue. BellSouth noted that the TRA has not yet issued a written order. BellSouth asserted that, therefore, the Commission should grant BellSouth's Petition and allow BellSouth to remove from the SQM/SEEM Plan the delisted elements identified in BellSouth's Notice filed on March 31, 2006.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

The Commission has reviewed and analyzed all of the comments filed by the parties and the relevant portions of the Act, FCC Orders, and the current, stipulated BellSouth SQM/SEEM Plan.

The Commission agrees with the CLP Parties and the Public Staff that the SQM/SEEM Plan was developed and put in place to ensure that BOCs would continue to meet their Section 271

[1] In FL Docket No. 041269-TP, Order No. PSC-06-0172-FOF-TP, at pages 69-70, the Commission found that performance data for services (delisted elements) no longer under Section 251(c)(3) shall be removed from BellSouth's SQM/PMAP/SEEM.

[2] In SC Docket No. 2004-316-C, Order No. 2006-136, at page 53, the Commission found that network elements that are delisted under Section 251(c)(3) should be removed from the SQM/PMAP/SEEM.

[3] In AL Docket No. 29543, *Final Order Resolving Disputed Issues*, at page 34, the Commission found that elements that are no longer required to be made available pursuant to Section 251 should be removed from BellSouth's SQM/PMAP/SEEM.

obligations after the FCC granted the BOCs interLATA authority. The Commission further agrees with BellSouth, the CLP Parties, and the Public Staff that a BOC's Section 251 and Section 271 unbundling obligations are independent of one another; in other words, relief from Section 251 unbundling does not automatically relieve a BOC of its Section 271 unbundling obligations. It is with the delisting of certain Section 251 UNEs that this issue has come to the forefront since, at the time of development of the SQM/SEEM Plan, there were no elements that were required to be unbundled only under Section 271.

The Commission further agrees with the Public Staff that in delisting Section 251 elements, the FCC has found those elements are not necessary and that CLPs are no longer impaired without access to those elements from the ILECs.[1] Therefore, delisted Section 251 elements are generally elements which are considered competitive and which the FCC has determined CLPs can purchase from other sources besides the ILEC. The FCC has generally determined that these delisted Section 251 elements are available from other sources, and those other sources would not be required to provide those elements in accordance with any specific service quality measurements; therefore, it seems logical that BOCs providing those services under Section 271 obligations should, likewise, not be required to adhere to any specific service quality measurements.

The Commission has also reviewed BellSouth's new, <u>stipulated</u> SQM/SEEM Plan which became effective on January 1, 2006. The SQM/SEEM Plan states in the Introduction that:

> [t]he SQM was developed to respond to the requirements of the Communications Act of 1996 <u>Section 251</u> (96 Act) which required BellSouth to provide non-discriminatory access to Competitive Local Exchange Carriers (CLEC). (emphasis added)

Further, Section 2.1 of the SEEM Plan states:

> In providing services <u>pursuant to the Interconnection Agreements</u> between BellSouth and each CLEC, BellSouth will report its performance to each CLEC in accordance with BellSouth's SQMs and pay remedies in accordance with the applicable SEEM, which are posted on the Performance Measurement Reports website. (emphasis added)

The Commission found in Finding of Fact No. 8 of its March 1, 2006 *Change of Law Order* that:

> [t]he Commission does not have the authority to require BellSouth to include Section 271 elements in ICAs entered into pursuant to Section 252, nor does the Commission have the authority to set rates for such elements.

No party objected to the Commission's decision in Finding of Fact No. 8 of the *Change of Law Order*.

[1] The Commission recognizes that the FCC has also used the "at a minimum" language in Section 251(d)(2) of the Act to take into account the extent to which unbundling requirements might undermine the incentives of both ILECs and CLPs to invest in new facilities and deploy new technology.

By reading Section 2.1 of the SEEM in conjunction with Finding of Fact No. 8 of the March 1, 2006 *Change of Law Order*, BellSouth will not be providing any Section 271 services pursuant to an ICA which should be subject to the SQM/SEEM Plan.

Therefore, based on the foregoing discussion, the Commission concludes that it is appropriate to grant BellSouth's Petition to remove the following delisted Section 251 elements from the SQM/SEEM Plan:

(1) UNE Line Sharing;
(2) UNE Switching;
(3) Sub-Loop Feeder;
(4) High Capacity Loops (DS1 and DS3) in unimpaired wire centers;
(5) Dark Fiber Loops (maintenance and repair metrics for the embedded base remain in the Plan until the September 2006 data month);
(6) Dedicated Transport (DS1 and DS3) in unimpaired wire centers;
(7) Dark Fiber Transport in unimpaired wire centers (maintenance and repair metrics for the embedded base remain in the Plan until the September 2006 data month);
(8) Entrance Facilities (i.e., local channels); and
(9) OCn Level Facilities.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of June, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper, III dissents from the majority's decision herein.
bp062006.01

DOCKET NO. P-100, SUB 133k

COMMISSIONER WILLIAM T. CULPEPPER, III, DISSENTING: I am unable to reach the result in this proceeding that has been obtained by the majority based upon the following reasoning:

1. The Commission has concluded herein that it agrees with the CLP Parties and the Public Staff that the SQM/SEEM Plan was developed and put in place to ensure that BOCs would continue to meet their Sec. 271 obligations after the FCC granted the BOCs interLATA authority.

2. The Commission has also concluded herein that it agrees with BellSouth, the CLP Parties, and the Public Staff that a BOC's Sec. 251 and Sec. 271 unbundling obligations are independent of one another.

3. A BOC must comply with Sec. 271 of the Telecommunications Act of 1996 in order for it to be able to provide interLATA (long distance) services.

4. Sec. 271 (c)(1)(A) requires a BOC to enter "into one or more binding agreements that have been approved under section 252 specifying the terms and conditions under which the BOC is providing access and interconnection to its network facilities for the network facilities of one or more unaffiliated competing providers of telephone exchange service… to residential and business subscribers." (emphasis added).

5. Sec. 271(c)(2)(A) requires BOCs to provide access and interconnection pursuant to one or more agreements described in paragraph (1)(A) that meet the requirements of subparagraph (B).

6. Subparagraph (B) of Sec. 271(c)(2) is a checklist of elements of access and interconnection that must be included in the Sec. 252 agreement.

7. Sec. 252(e)(1) specifically requires approval of interconnection agreements (ICAs) by "the State Commission". (emphasis added)

8. In Docket P-772, Sub 8, *In the Matter of Joint Petition of New South Communications Corp. et al for Arbitration with BellSouth Telecommunications, Inc.*, this Commission found the following Finding of Fact No. 9:

> BellSouth shall permit a requesting carrier to commingle a UNE or a UNE combination obtained pursuant to Section 251 with one or more facilities or services that a requesting carrier has obtained at wholesale from an ILEC pursuant to a method other than unbundling under Section 251(c)(3) of the Act, including those obtained as Section 271 elements. (emphasis added).

9. I am unable to reconcile the contents of paragraphs 3-8 above with this Commission's Finding of Fact No. 8 of the Change of Law Order (in which I did not participate) that "[t]he Commission does not have the authority to require BellSouth to include Section 271 elements in ICAs ...," which I believe to be erroneous.

Therefore, I respectfully dissent.

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

DOCKET NO. P-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the matter of		
Petition for Rulemaking to Revise Billing	)	ORDER AMENDING
and Collection Procedures for	)	RULE R12-17(i)(2)(A) AND
Telecommunications Companies Regarding	)	PERMITTING MODIFICATION
Local Disconnection and Toll Denial	)	OF BILL FORMAT

BY THE COMMISSION: On December 16, 2005, BellSouth Telecommunications, Inc. ("BellSouth") requested that the Commission amend Rule R12-17(i)(2)(A) and approve modifications to BellSouth's bill format as permitted by R12-17(i)(2)(F). On January 22, 2006, the Commission requested that interested parties submit comments by no later than January 31, 2006, and that BellSouth submit reply comments by February 17, 2006. On January 31, 2006, the Public Staff and the Attorney General filed comments. BellSouth met with the Attorney General's office and the Public Staff prior to the filing of those comments. On January 31, 2006, BellSouth filed a modified motion to amend bill format which reflected suggestions made by those offices. On February 17, 2006, BellSouth filed reply comments.

BellSouth initially recommended that all unregulated charges on the bill should be marked with a double asterisk and an associated footnote at the bottom of the page(s) where these asterisks appear in lieu of current practice of providing regulated and unregulated charges in separate sections of the bill. After reviewing the proposal with the Public Staff and the Attorney General, the parties noted that confusion could arise for customers with interstate charges on their bills under the initial proposal. To alleviate this concern, BellSouth made modifications which resolve much of the confusion by using the double asterisks unregulated indicator only on BellSouth Telecommunications pages of the bill with an associated footnote stating, "Unregulated Charge. Local service will not be disconnected for nonpayment of unregulated charges." All remaining pages of the bill, including carrier pages, would have a blanket statement at the bottom of the page that states, **"NONPAYMENT OF ITEMS APPEARING ON THIS PAGE WILL NOT RESULT IN DISCONNECTION OF YOUR LOCAL TELEPHONE SERVICE; HOWEVER, COLLECTION OF UNPAID CHARGES MAY BE PURSUED BY THE SERVICE PROVIDER."** This modified format makes it much easier for customers to identify charges on their bill that must be paid in order to retain local telephone service. The Public Staff and the Attorney General support the modified proposal in their January 31, 2006 filings.

BellSouth also requested modifications of Rule R12-17(i)(2)(A), which was promulgated by the Commission in its April 3, 2000 Order. Rule R12-17(i)(2)(A) currently requires that the service provider's name and toll free contact number be provided on each bill page, "where the services of any provider other than the billing utility are stated." BellSouth's original proposal allowed the company to place contact information on the first page of each service provider's section of the bill and would have eliminated duplication of this information on each and every page as required in the current rule. As a result of discussions with the Public Staff, BellSouth modified the original proposal as follows.

(A) Where the services of any provider other than the billing utility are stated, and where all charges from that service provider are included on consecutive pages within the bill, the name of the service provider offering the service shall be clearly shown on every page and a toll-free contact number or numbers for the service provider shall be clearly shown on the first page of the service provider's section of the bill. Otherwise, the name of the service provider and the toll-free contact information must be included on each bill page where the services of any provider other than the billing utility are stated. The toll-free contact number for the service provider may be a number of the company that handles the inquiry for the service provider.

The Attorney General and the Public Staff do not object to the language outlined above.

Finally, in his comments, the Attorney General expressed concern that BellSouth's current bill fails to specify the precise amount that the consumer owes for local service. As a result, the consumer cannot easily discern the exact amount that must be paid in order to maintain local service. To rectify its concern, the Attorney General proposed that BellSouth change its bill format to specify the precise amount that the consumer owes for local service within 90 to 120 days.

BellSouth objected to the Attorney General's proposal primarily because the proposed change would require a minimum of six to nine months to accomplish. BellSouth also noted that the bill provision in question had been in place for a number of years and that it would prefer to implement a change of this magnitude coincident with more sweeping changes that it would be proposing by mid-2007.

After careful consideration of the comments of the parties, the Commission concludes that the changes proposed by BellSouth in its filings of December 16, 2005 and January 31, 2006 which were agreed upon after discussions with the Public Staff and the Attorney General should be adopted. Further, the Commission concludes that BellSouth's current bill format, which does not specify the precise amount that must be paid in order for the consumer to maintain local service, is a concern and should be corrected. Correcting this problem will be a large undertaking. For this reason, the Commission cannot agree that BellSouth should be required to propose a solution to this problem within 90 to 120 days as suggested by the Attorney General. Nor can the Commission agree that resolution to this problem be delayed until mid-2007 as suggested by BellSouth. After carefully considering the arguments of the parties and the importance of this information to consumers, the Commission concludes that BellSouth shall revise its bill format so that the consumer can precisely and easily identify the amount due in order to maintain local service within 180 days of the date of this order.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective as of the date of this Order, Rule R12-17(i)(2)(A) is amended as follows:

> Where the services of any provider other than the billing utility are stated, and where all charges from that service provider are included on consecutive pages within the bill, the name of the service provider offering the service shall be clearly shown on every page and a toll-free contact number or numbers for the service provider shall be clearly shown on the first page of the service provider's section of the bill. Otherwise, the name of the service provider and the toll-free contact information must be included on each bill page where the services of any provider other than the billing utility are stated. The toll-free contact number for the service provider may be a number of the company that handles the inquiry for the service provider.

2. That BellSouth shall modify its bill format by using the double asterisks unregulated indicator only on BellSouth Telecommunications pages of the bill with an associated footnote stating, *"Unregulated Charge. Local service will not be disconnected for nonpayment of unregulated charges."* All remaining pages of the bill, including carrier pages, would have a blanket statement at the bottom of the page that states, **"NONPAYMENT OF ITEMS APPEARING ON THIS PAGE WILL NOT RESULT IN DISCONNECTION OF YOUR LOCAL TELEPHONE SERVICE;**

HOWEVER, COLLECTION OF UNPAID CHARGES MAY BE PURSUED BY THE SERVICE PROVIDER."

3. That, BellSouth shall revise its bill format so that consumers can precisely and easily identify the amount due in order to maintain local service within 180 days of the date of this order.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of April, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Lh032006.01

DOCKET NO. P-100, SUB 152

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Competitive Access to Commercial) ORDER PROMULGATING FINAL RULES
and Residential Developments)

BY THE COMMISSION: On October 3, 2005, the Public Staff, as per Commission Order, filed a Proposed Rule in this docket attached as Exhibit A to its filing. The Public Staff stated that, in presenting the Proposed Rule it attempted to adhere to the Commission's ruling and not relitigate matters already decided, even when they were decided adversely to the Public Staff. The Public Staff noted that the enactment of Session Law 2005-385 (HB 1468) had rendered moot any rules regarding carriers of last resort, as well as the letter to customers attached as Exhibit A of the Commission's October 29, 2004, Order. The Commission thereupon sought comments on the Public Staff's Proposed Rule.

Comments

North Carolina Real Estate Alliance (NCREA) objected to the Proposed Rules' banning of weighted commissions in exclusive contracts, arguing that such a provision is not supported by the record and goes beyond the Commission's ruling on previous motions. Such a ban is not in the public interest, and the General Assembly has recently rejected legislation that would have accomplished by statute that which the Public Staff seeks to have imposed by regulation. Specifically in this regard, the NCREA referenced HB1470, which would, it said, have banned exclusive Preferred Provider Contracts and created affirmative obligations related to access. This bill never made it out of the House Public Utilities Committee. Thus, the NCREA argued, the Commission must infer that there are sound policy reasons for permitting exclusive contracts that include weighted commissions. Indeed, NCREA argued that exclusive contracts are vital to ensuring the long-term prospects for competition in the residential market.

The NCREA, however, did not object to the remainder of the proposed Rule so long as it is interpreted so as (1) not impose mandatory access to private property within North Carolina and (2) to recognize the ability of a property owners to obtain fair compensation for the use of their property by means of freely negotiated contracts containing weighted commissions.

ALLTEL Carolina, Inc. (ALLTEL) stated that it supports the Public Staff's Rule R20-2 with one exception—that the proposed Subsection 2(g) is too broadly written. ALLTEL believed that Subsection 2(g) should be replaced with a provision focused solely and explicitly on Fiber-to-the-Home (FTTH) deployment. The Proposed Subsection 2(g)(2) now reads as follows:

> *The Exempting Provider Attachment shall state either (A) that the exempted provider is a local exchange company and is not required by federal law to make subloops available to competitors in any of the developments to which the notice is applicable, or (B) that the exempted provider is a competing local provider, and if it were a local exchange company, it would not be required by federal law to make subloops available to competitors in any of the developments to which the notice is applicable; and its shall briefly specify the exempted provider's legal basis for making such statement.*

ALLTEL recounted that, in the Further Order on Reconsideration, the Commission had used the term "subloop/weighted commission nexus" as referring to the case in which, if a PPC carrier voluntarily chooses or is otherwise required to offer subloop unbundling at a given development, then it would be permitted to offer weighted commissions as to that specific development. ALLTEL asserted that the Commission went on to conclude that, to the extent that an incumbent local exchange company (ILEC) has been relieved of its federal obligation to unbundle its loops where FTTH is deployed, the subloop/weighted commission nexus would not apply. ALLTEL further asserted that no other situation or scenario warranting exemption other than FTTH was set out in any of the comments addressing the motions for reconsideration, and no such situations currently exist.

ALLTEL contended that the language proposed by the Public Staff above is too broad because it will simply allow competing local providers (CLPs) who seek to exclude other competitors from the developments they target to file Exempted Provider Attachments claiming exemptions and then burden the ILEC with challenging the legal basis for the claimed exemption. ALLTEL argued that the Commission's establishment of the subloop/weighted commission nexus was intended to eliminate such roadblocks and to condition commission payments by the Preferred Provider on subloop provisioning to carriers desiring to compete with the Preferred Provider in every situation *except for the specific circumstance presented by the FTTH development*. Any exemption from the general requirement to provide subloops (if a Preferred Provider is willing to pay weighted commissions) should be narrowly tailored to the situation where FTTH has been or will be deployed. The Preferred Provider should have to support its FTTH claim via plant inspection by the requesting ILEC or competing carrier. If that inspection fails to prove that FTTH exists in the PPC development, then the ILEC should be able to file an expedited petition for the Commission to require the Preferred Provider to provide subloops. Thus, Proposed Subsection 2(g) should be struck and replaced with a provision focused solely and explicitly on FTTH deployment.

Verizon South, Inc. (Verizon) stated that, for the most part, it believed that the Public Staff had fairly captured the Commission's various rulings in this docket but it had several modifications to suggest.

First, with reference to Subsection (a)(2) and (a)(8), Verizon argued that the proposed rule is ambiguous concerning what constitutes a "preferred provider" and "preferred provider contract" in that the definitions were circular—i.e., a local service provider is a "preferred provider" if it has entered into a preferred provider contract and a "preferred provider contract" is one designating a "preferred provider." Verizon felt that a strict reading would enable a carrier to eliminate all notice requirements simply by using some other phrase than "preferred provider" in its contract. Moreover, a "preferred provider contract" must give the "preferred provider" special rights "not available to other local service providers. Verizon felt that this cannot be sufficient to convert the contract into a PPC, since a local service provider could enter into non-exclusive marketing agreements with the developer. Yet, Verizon argued, if other local service providers do not take advantage of contractual opportunities with the developer, or if the developer decides not to offer the same contract to another provider, the agreement might still fall within the terms of the rule because the "special rights" for marking services would "not be available to other local service providers" under any other contract with the developer. Such non-exclusive arrangements should not fall within the definition of a PPC under the Commission rule. To address these concerns, Verizon proposed that the rule narrow the definition of "preferred provider contracts" subject to notice to include "exclusive provider," "exclusive access," "exclusive provisioning," or weighted commission terms under exclusive agreements. In this manner, a local service provider would only be required to provide notice for contracts that include terms and conditions that the Commission has determined are either "anticompetitive and void" or conditioned upon the availability of unbundled subloops in the affected development. To require notice for contracts that do not contain such provisions serves no valid regulatory purpose.

Accordingly, Verizon suggested that Subsection (a)(2) be rewritten to read:

> *"(2) 'Electing provider' means a preferred provider that is a competing local provider and that has chosen to make subloops available to competitors pursuant to subsections (f) and (h) of this rule."*

Subsection (a)(8) should be rewritten to read:

> *"(8) 'Preferred provider contract' means a contract between a particular local service provider and the owner or developer of a development that contains exclusive access provisions, exclusive provisioning provisions, and/or weighted commission provisions that explicitly exclude the right the of the developer to obtain weighted commission from any other local service provider."*

Second, Verizon objected to Subsection (d) of the proposed rule that declares weighted commissions to be "contrary to public policy and void" except under certain conditions." The Commission has in fact held that weighted commissions are not anticompetitive, and thus the rule's statement does not fairly reflect the Commission's orders. Verizon proposed what it believed to be more neutral and accurate language as follows:

> *"(d) Weighted commission provisions in preferred provider contracts may not be enforced by the local service provider, except as provided in subsections (f) and (g) below.".*

Third, Verizon objected to subsection (e)(1) of the proposed rule requiring notice for "each development where the provider has entered into a preferred provider contract, *or intends to enter into such a contract.*" (Emphasis added). Unless and until executed, a contract does not exist and thus no notice should be required. In fact, provision of such notice before a contract is executed would cause competitive harm. Thus, the phrase should be deleted and the provision amended as follows:

> *"(1) For each development where the provider has entered into a preferred provider contract, the Preferred Provider Notice shall provide the following information".*

Furthermore, Subsection (e)(1)(F) should be rewritten to read:

> *"Whether the contract includes weighted commissions from any other local service provider, and, if so, whether the provider is filing an Electing Provider Attachment under subsection (f) of this rule, whether the provider is a local exchange company that provides access to subloops pursuant to federal law and is not required to file an Electing Provider attachment under subsection (f), or whether the provider is filing an Exempted Provider Attachment under subsection (g) of this rule."*

Fourth, Verizon saw no valid purpose to Subsection (f), the "electing provider attachment," with respect to incumbent carriers. Terms and conditions under which ILECs provide subloops are already set forth in the terms of the interconnection agreements and are available publicly. Accordingly, Verizon proposed that Subsection (f) be rewritten to read:

> *(f) A preferred provider that is a competing local provider may become an electing provider by filing with the Commission an Electing Provider Attachment that meets the requirements of subdivisions (1) through (3) below. An electing provider, within the developments specified in its Electing Provider Attachment, may enter into preferred provider contracts containing such provisions. Notwithstanding any other provision of this section, a local exchange company need not file an Electing Provider Attachment in order to enter into preferred provider contracts containing weighted commission provisions and may continue to enforce existing preferred provider contracts containing such provisions."*

Southeastern Competitive Carriers Association (SECCA), like Verizon, expressed concern regarding Subsection (a)(8), the definition of "Preferred Provider Contract." SECCA argued that, if the "preferred provider" designation is maintained as a separate component of the PPC definition, whether a provider is officially designated as a "preferred provider" by an owner or developer should not be determinative of whether a provider has entered into a PPC. In other words, if the requirement is maintained, the requirements should be stated in the alternative rather than as two essential components. Otherwise, a provider could avoid compliance with the rule by simply avoiding being characterized as a preferred provider.

With respect to Subsections (a)(3) and (4), the definitions of "exclusive access" and "exclusive provisioning," SECCA argued that these definitions should be amended to add clarity and address additional circumstances consistent with the Commission's intent to prohibit all restrictions on access and provisioning, as well as providing a more meaningful distinction between "access" restrictions and "provisioning" restrictions. In the absence of such clarifications, restrictions on access imposed on a party of the developer would not be prohibited; there could be room for debate as to whether restrictions regarding access to easements and other\ rights-of-way are prohibited; and requirements which have the effect of restricting access, such as imposing an uneconomic fee for access or conditioning the right in other ways which are anticompetitive in nature, would not be prohibited.

Accordingly, SECCA recommended that Subsection 2(a)(3) should be revised to read:

"(3) 'Exclusive access provisions' are provisions of a preferred provider contract that prohibit the developer, manager, owner or other party controlling access to a development from allowing competitors of the preferred provider to enter upon the development premises or easements and right-of-way appurtenant thereto, or provisions of a preferred provider contract that require the developer, manager, owner or other party controlling access to a development to impose restrictions or requirements on such third party access which are not imposed on the preferred provider and which are anticompetitive in nature."

Similarly, Subsection 2(a)(4) should be revised to read:

"(4) 'Exclusive provisioning provisions' are provisions of a preferred provider contract that prohibit the developer, manager, owner or other party controlling access to a development from allowing competitors of the preferred provider to provide services in a development or provisions of a preferred provider contract that require the developer, manager, owner or other party controlling access to the development to impose restrictions or requirements on the provisioning of such third party service which are not imposed on the preferred provider and which are anticompetitive in nature."

With respect to Subsection (g), concerning exempt provider certifications, SECCA recommended that the subsection be expanded to explicitly recognize the right of the local service provider to challenge the self-certification that a provider is exempt. The party asserting the exemption should bear the burden of proof. SECCA's proposed Subsection (g)(4) would read:

"(4) A local service provider may challenge an Exempted Provider Attachment by filing a petition seeking review of such Attachment with the Commission. In the event of such a challenge, the party asserting exemption shall bear the burden of demonstrating entitlement to the exemption."

Finally, SECCA recommended that, to facilitate electronic monitoring of and access to Preferred Provider Notice and Preferred Provider Attachments, the Commission should require filing such Notices and Attachments in a docket set aside for that purpose and specify filing procedures for them.

CTC Exchange Services, Inc. (CTC) stated that it was generally supportive of the Public Staff's Proposed Rule, but it identified several aspects that it believes are problematical.

First, CTC expressed concern over Subsection (e)(2) concerning filing of the Preferred Provider Notice. Specifically, CTC objected to that part of the Subsection requiring advance notice of the terms of the PPC. This is both impractical and competitively damaging to CTC, and there is nothing in the Commission's prior rulings requiring such advance notice. CTC suggested that Subsection (e)(2) amended to require the submission of the Notice within 45 days *after* the PPC is entered into.

Second, CTC expressed identical concerns with respect to Subsection (f)(3), concerning updating Provider Attachment updates *before* the electing provider enters into any PPC with weighted commissions. Here also, CTC suggested amending the provision to require the submission of any such update within 45 days *after* the electing provider has entered into any PPC with weighted commission provisions relating to any of the additional development.

Public Staff Reply Comments

Public Staff responded to each of the comments of the above parties, in some cases accepting their comments and proposing revisions to the rules and in other cases rejecting those comments. The Public Staff's revised rule (marked-up) was attached to its filing as Exhibit A.

With respect to the comments of ALLTEL and its argument that Subsection (2)(g), relating to exempted providers, was too broadly worded, is susceptible to fraud, and should be specifically limited to FTTH, the Public Staff pointed out that FCC regulations are likely to change as the telecommunications industry continues to evolve and, therefore, the wording must be written broadly enough to cover every circumstance, present or future, in which ILECs are exempted from subloop obligations so that the rule will not have to amended whenever the FCC revises it regulations. ALLTEL also argued that there should be a procedure allowing the competitor of a preferred provider to challenge an Exempted Provider Attachment on the grounds that the exemption asserted is fictitious. On this point, the Public Staff agreed with ALLTEL (and SECCA, which had similar concerns) and proposed the revisions to proposed rule (g)(4) to read as follows:

> "*(4) A local service provider may challenge an Exempted Provider Attachment by filing a Petition seeking review of such Attachment with the Commission. In the event of such challenge, the party asserting the exemption shall bear the burden of demonstrating entitlement to the exemption.*"

In order to deter fictitious assertions, the Public Staff suggested that Subsection (g)(2) should be revised to read:

> *(2) The exempted Provider Attachment shall state either (A) that the exempted provider is a local exchange company and is not required by federal law to make subloops available to competitors in any of the developments to which the attachment is applicable, or (B) that the exempted provider is a competing local provider, and if it were a local exchange company, it would not be required by federal law to make subloops available to competitors in any of the developments to which the attachment is applicable. For each development for which exemption is asserted, the exempted provider shall specify with particularity its legal basis for asserting the exemption.*

The Public Staff also proposed certain other minor changes to Subsection (g)(2) in the interests of clarity which it said do not affect the substance of the rule and which are uncontroversial.

The Public Staff also recommended that a challenger have the right to inspect the preferred provider's facilities to verify if an exemption based on FTTH or Fiber-to-the-Curb (FTTC) is allowable. The Public Staff proposed a new Subsection (g)(5) to read:

> "(5) *When the basis for an exempted provider's claim of exemption is that it is providing service through fiber to the home or fiber to the curb, the exempted provider shall, upon written request of any other provider, meet with such provider on the premises of the development to demonstrate that is in fact providing service through fiber to the home or fiber to the curb.*"

With respect to the comments of CTC, Public Staff was skeptical of CTC's view, shared by Verizon, that preferred providers would be competitively disadvantaged by Subsections (e)(2) and (f)(3) specifying the timetable for filing a new or updated Preferred Provider Notice when a carrier enters into a new PPC and for filing a new or updated Electing Provider Attachment when a carrier that is entering into a new PPC desires to offer subloops to competitors and thereby retain the option of using weighted commissions. CTC wanted the timetable to be 45 days *after* it had entered into a new PPC, while Verizon preferred to delete the phrase "or *intends* to enter into such contract" from Subsection (e)(1). The Public Staff replied that the proposed filing procedure was based on the discussion of Decision 12 at page 23 of the Commission's April 14, 2005, Order. The Public Staff pointed out that the proposed rule says only that the filing is to be made "before" a carrier enters into a new PPC. Indeed, the filing can be made on the same day the PPC is executed, so long as the filing occurs before the contract is signed. However, the Public Staff stated that it does not object to deleting from Subsection (e)(1) the phrase "or intends to enter into such contract," as recommended by Verizon and rewriting the provision to state that a Preferred Provider Notice must be filed "[f]or each development where the provider has entered into, or will enter into, a preferred provider contract," so as to eliminate the implication that the obligation to file a Preferred Provider Notice is triggered by a carrier's in-house decision to seek a PPC from a particular developer. It would still be true that a new or updated Preferred Provider Notice must be filed before a new PPC is executed.

The Public Staff further noted that, because of the importance of filing Preferred Provider Notices in a timely manner and making PPCs public, the Commission must have the ability to impose a significant penalty on a carrier that fails to file the required notice. If the only sanction is a one-time \$1,000 fine under G.S. 62-310(a), this may obviously be inadequate to deter wrongdoing. Accordingly, the Public Staff proposes a new Subsection (h) to read as follows:

> "*No local service provider may maintain a preferred provider contract in effect in any development unless it has duly filed with the Commission a Preferred Provider Notice that makes reference to the development, together with any applicable Electing Provider Attachment or Exempted Provider Attachment.*"

Thus, if a carrier enters into a PPC for a new development but does not file an updated Preferred Provider Notice until 45 days later, there will be a continuing violation, and the carrier could be penalized up to \$45,000.

With respect to the comments of the NCREA, the Public Staff strongly disagreed with the NCREA's contention that the Commission should reconsider its decision to prohibit exclusive PPCs, as well as its decision to allow weighted commission only when the preferred provider offers subloops to competitors. Aside from the fact that the Commission's decisions have already been subject to two rounds of motions for reconsideration, the NCREA's contentions concerning what the

General Assembly enacted or failed to enact are simply inapposite. If, for example, the General Assembly had wished to make weighted commissions generally available without regard to whether or not subloops were offered to competitors, it could have done so; but such legislation was neither proposed nor enacted.

With respect to the comments of SECCA, the Public Staff agreed that the definition of "preferred provider contract" was very important and should prevent a preferred provider from evading regulation simply by changing the terminology of its contracts. The Public Staff agreed that its originally proposed definition was inartfully worded, and it revised the definition to close the loophole identified by SECCA as follows:

"(a)(8) "Preferred provider contract" means a contract between a particular local service provider and the owner or developer of a development giving the preferred provider special status or rights not available to other local service providers."

The Public Staff also agreed with SECCA's proposals to modify the definitions of "exclusive access provisions" and "exclusive provisioning provisions" in Subsection (a)(3) and (4). The former should read:

"(a)(3) "Exclusive access provisions" are provisions of a preferred provider contract that prohibit the developer, manager, owner or other party controlling access to a development from allowing competitors of the preferred provider to enter upon the development premises or easements and rights-of-way appurtenant thereto, or provisions of a preferred provider contract that require the developer, manager, owner or other party controlling access to a development to impose restrictions or requirements on such third party access which are not imposed on the preferred provider and which are anticompetitive in nature."

Similarly, the latter should read:

"(a)(4) "Exclusive provisioning provisions" are provisions of a preferred provider contract that prohibit the developer, manager, owner or other party controlling access to a development from allowing competitors of the preferred provider to provide services in a development or provisions of a preferred provider contract that require the developer, manager, owner or other party controlling access to a development to impose restrictions or requirements on the provisioning of such third party service which are not imposed on the preferred provider and which are anticompetitive in nature."

Lastly, the Public Staff was agreeable to SECCA's contention that the Preferred Provider Notices and their attachments should be filed in a docket set aside for that purpose, although the mechanics of this need not be in the rule itself. The Public Staff, however, proposed a new Subsection (i) dealing with filing requirements as follows:

"(i) Preferred Provider Notice Electing Provider Attachments and Exempted Provider Attachments shall be subject to the following filing requirements: (1) Each preferred provider shall file its Preferred Provider Notice, together with any attachments, in a docket to be designated by the Commission. (2) Each preferred provider Notice filed

by a particular preferred provider shall be labeled 'Preferred Provider Notice—Version 1.' The first updated Preferred Provider Notice filed by such provider shall be labeled 'Preferred Provider Notice—Version 2,' and subsequent updates shall be numbered sequentially. (3) Whenever an Electing Provider Attachment or Exempted Provider Attachment is updated, the provider shall file an update of the entire Preferred Provider Notice, including the Attachments, with a new version number, even if the only changes are in on the Attachments."

With respect to the comments of Verizon, the Public Staff found less to agree with. The Public Staff argued that Verizon's view that the definition of "preferred provider contracts" should include only contracts with exclusive access provisions, exclusive provisioning provisions, or weighted commission provision would give an incentive to carriers to treat their contracts as falling outside of the definition. Verizon appears to be using this suggestion as a means to seek further reconsideration, and this is inappropriate. The Public Staff furthermore viewed Verizon's objections as to Subsections (d), (e)(1), and (f) as being essentially quibbles.

Additional Comments Regarding Subsection (g)(5)

On December 5, 2005, **Verizon** filed a Motion for leave to file a Response to the Public Staff's Reply Comments regarding Subsection (g)(5) only. Subsection (g)(5) as proposed by the Public Staff would give a competitive provider the right to demand a physical inspection of a preferred provider's fiber facilities when the preferred provider has deployed fiber facilities to such premises. The Commission granted Verizon's Motion and sought replies from the other parties.

Verizon opposed the Public Staff's proposed provision for several reasons. First, Verizon stated it provided access to UNEs only pursuant to its interconnection agreement (ICA), and any right to inspect must be governed exclusively by the provisions of the ICA. Second, even if the Commission could lawfully impose such a right to inspect, the Public Staff's proposal does not adequately protect Verizon's proprietary network information from disclosure to competitors. The Public Staff's proposal neither defines what kind of "demonstration" the requesting provider can demand, nor permit Verizon to demand that the competitor enter into a nondisclosure agreement. Third, physical inspection is not necessarily a simple matter, as it would involve the dispatch of technicians and other personnel and may require excavation of facilities. There is no limit on the number of inspections, which could be highly repetitive, lead to harassment, and be a disincentive to even deploying such facilities, contrary to federal policy.

Public Staff rejected Verizon's view that, under the Act, ILECs are not required to provide UNEs to competitors except pursuant to ICAs and that the Commission thus has no power to impose any obligation on an ILEC beyond the obligations the ILEC has undertaken in the ICA. This "interconnection agreements-only" theory is distinguishable from this situation, and its underlying basis was soundly rejected by the Commission in its *Order Denying Petition* issued on September 22, 2003, in Docket No. P-19, Sub 454 regarding transit obligations. The Public Staff also rejected Verizon's view that requiring a carrier to reveal its fiber facilities to competitors in the situation at issue would be overly costly and burdensome. The Public Staff continues to believe that in most cases the physical disclosure of fiber facilities will indeed be a simple matter. Under Subsection (g)(4) competitors retain the right to challenge an Exempted Provider Attachment, and, in any such challenges, the burden of proof is on the party claiming the exemption.

The Public Staff further noted that, even if a preferred provider makes use of FTTP, that fact is not in itself sufficient to exempt the preferred provider from its obligation to offer subloops. Under the FCC's *Triennial Review Order*, when an ILEC provides service to mass market customers through FTTP, it is not required to offer unbundled loops or subloops to competitors—except that, if it has overbuilt existing copper lines with fiber facilities and the copper facilities remain available for use, the ILEC must offer unbundled copper loops or subloops. Also, ILECs must offer loops and subloops over fiber for narrowband services when the ILEC overbuilds fiber over copper facilities and then retires the copper facilities. When enterprise customers are served by FTTP facilities, the ILEC must continue to offer unbundled loops and subloops for access to multi-unit premises wiring.

Nevertheless, the Public Staff concluded that it would be appropriate to delete Subsection (g)(5), provided some basic protections can be built into other portions of the rule. Therefore, the Public Staff has revised its proposed rules in Subsections (g)(2) and (3). It has included a requirement that exempted providers file affidavits, signed by engineers with direct personal knowledge of the facilities serving each development to which the Exempted Provider Attachment applies, specifying with particularity the provider's legal basis for claiming an exemption. To help protect against the danger of creating an incentive to delay challenge proceedings, the Public Staff suggested adding to Subsection (g)(4) a provision to specify that, in a challenge proceeding, the party claiming the exemption bears the burden of proof by clear and convincing evidence and a provision to give challenge proceedings priority on the Commission's docket to the extent reasonably practicable. The higher burden of proof is warranted because in a challenge proceeding the relevant facts are, to a unique degree, within the exclusive knowledge and control of the party seeking the exemption. Docket priority is, of course, not absolute but only to the extent reasonably practicable.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that good cause exists to adopt the further revised rules as proposed by the Public Staff, with a minor exception set out below.

The Public Staff correctly observed that the purpose of the rules is to effectuate the final decisions of the Commission made after abundant consideration and reconsideration. Although some parties could not resist the temptation to seek some additional measure of reconsideration, by and large the comments of the parties were on point and highly constructive. The Public Staff in its Reply Comments admitted their merits and incorporated many of the changes into the rule. Overall, the process by which rules were proposed and then modified pursuant to thoughtful comments was exemplary and illustrative of how such a process ought to work.

With respect to the controversy over ways to verify Exempted Provider Attachments, the Commission believes that the Public Staff has generally struck the correct balance to ensure that claims for Exempted Provider Attachments are well-founded, while avoiding anything which may create an undue physical intrusion on property. Accordingly, the Public Staff's recommendation should be adopted which deletes Subsection (g)(5) and slightly adjusts Subsection (g)(3) and (4). Thus, the Public Staff's proposed Subsection (g)(3) should be amended to read: "*For each development for which exemption is asserted in an initial or updated Exempted Provider Attachment, the provider shall submit an affidavit, signed by an engineer with direct personal knowledge of the* *facilities serving the development, that specifies with particularity the provider's factual and legal basis for asserting the exemption."* The Public Staff's proposed Subsection (g)(4) should be amended to read: *"A local service provider may challenge an Exempted Provider Attachment by filing a Petition seeking review of such Attachment with the Commission. In the event of such a challenge, the Public Staff shall investigate such challenge and file its report and recommendations concerning the merits of such challenge within 30 days of the filing of the challenge. The party asserting exemption shall bear the burden of demonstrating entitlement to the exemption by clear and convincing evidence. Any such challenge shall, to the extent practicable, be given priority on the Commission's docket."*

The amendment to Subsection (g)(3) is largely technical in nature, providing that the affiant should specify with particularity both the *factual* and legal basis for the assertion of the exemption. The amendment to Subsection (g)(4) is more substantive. It provides that the Public Staff must investigate a challenge to the Exempted Provider Attachment and make a report within 30 days. As part of its investigative powers, the Public Staff can have resort to the provisions of G.S. 62-34(b), which provides in pertinent part that the Public Staff "may during all reasonable hours enter upon any premises occupied by any public utility, for the purpose of making the examinations and tests and exercising any power provided for in this Article, and may set up and use on such premises any apparatus and appliances necessary therefor." The Public Staff may therefore make site visits for inspection and verification purposes which would be specifically conducted pursuant to statute.

IT IS, THEREFORE, ORDERED as follows:

1. That the rules set out in Exhibit A be promulgated as final rules.

2. That Docket No. P-100, Sub 152c, entitled "Notices and Attachments Pursuant to Rule R20-2" be established and that all Preferred Provider Notices, Electing Provider Attachments, and Exempted Provider Attachments be filed therein.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of January, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner William T. Culpepper III did not participate.

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EXHIBIT A
Page 1 of 6

R20-2 FAIR COMPETITION AMONG LOCAL TELECOMMUNICATIONS SERVICE PROVIDERS

(a) For purposes of this rule, the following definitions shall apply:

(1) "Development" means a residential subdivision, office park, shopping center or other area with clearly defined boundaries being developed as a unified entity by one or more landlords or developers.

(2) "Electing provider" means a preferred provider that has chosen to make subloops available to competitors pursuant to subsections (f) and (h) of this rule.

(3) "Exclusive access provisions" are provisions of a preferred provider contract that prohibit the developer, manager, owner or other party controlling access to a development from allowing competitors of the preferred provider to enter upon the development premises or easements and rights-of-way appurtenant thereto, or provisions of a preferred provider contract that require the developer, manager, owner or other party controlling access to a development to impose restrictions or requirements on such third party access which are not imposed on the preferred provider and which are anticompetitive in nature.

(4) "Exclusive provisioning provisions" are provisions of a preferred provider contract that prohibit the developer, manager, owner or other party controlling access to a development from allowing competitors of the preferred provider to provide services in a development or provisions of a preferred provider contract that require the developer, manager, owner or other party controlling access to a development to impose restrictions or requirements on the provisioning of such third party service which are not imposed on the preferred provider and which are anticompetitive in nature.

(5) "Exempted provider" means a preferred provider that is a local exchange company and is not required under federal law to make subloops available to its competitors, or a preferred provider that is a competing local provider and would not, if it were a local exchange company, be required to make subloops available to its competitors.

(6) "Local service provider" includes any competing local provider, as defined in G.S. 62-3(7a), and any local exchange company, as defined in G.S. 62-3(16a).

(7) "Preferred provider" means a local service provider that has entered into a preferred provider contract.

(8) "Preferred provider contract" means a contract between a particular local service provider and the owner or developer of a development, giving the preferred provider special status or rights not available to other local service providers.

(9) "Weighted commission provisions" are provisions of a preferred provider contract providing for the payment of commissions to an owner or developer that (A) are based on the number of customers in the development who purchase service from the preferred provider, or (B) are based on a percentage of the revenues received by the preferred provider from customers in the development, or (C) otherwise provide a financial incentive for the owner or developer to exclude competitors of the preferred provider from the development.

(b) Exclusive provisioning provisions in preferred provider contracts are anticompetitive and void.

(c) Exclusive access provisions in preferred provider contracts are anticompetitive and void.

(d) Weighted commission provisions in preferred provider contracts are contrary to public policy and void, except as provided in subsections (f) and (g) below.

(e) Every preferred provider shall file with the Commission a Preferred Provider Notice. There shall be a single notice for each preferred provider, rather than separate notices for each development where a preferred provider contract exists. The notice shall comply with the following requirements:

(1) For each development where the provider has entered into, or will enter into, a preferred provider contract, the Preferred Provider Notice shall provide the following information:

(A) The name and location of the development.
(B) The identity of the parties to the contract.
(C) The identity of the local exchange company, if any, in whose franchise area the development is located.
(D) Whether the contract includes exclusive provisioning provisions.
(E) Whether the contract includes exclusive access provisions.
(F) Whether the contract includes weighted commission provisions, and if so, whether the provider is filing an Electing Provider Attachment under subsection (f) of this rule or an Exempted Provider Attachment under subsection (g) of this rule.

(2) The Preferred Provider Notice shall be filed within 21 days after the effective date of this rule, if the provider is a party to any existing preferred provider contract. Before entering into any new preferred provider contract, a local service

provider shall file an updated Preferred Provider Notice (or a new notice, if it has not filed such a notice previously) containing the information provided in subdivision (1) above with respect to the new preferred provider contract. Before amending any preferred provider contract in a manner that affects the information in the Preferred Provider Notice, a local service provider shall file an updated Preferred Provider Notice.

(f) A preferred provider may become an electing provider by filing with the Commission an Electing Provider Attachment that meets the requirements of subdivisions (1) through (3) below. An electing provider, within the developments specified in its Electing Provider Attachment, may enter into preferred provider contracts containing weighted commission provisions and may continue to enforce existing preferred provider contracts containing such provisions.

(1) The Electing Provider Attachment shall be attached to the electing provider's Preferred Provider Notice. It shall identify the name and location of each development to which it is applicable.

(2) The Electing Provider Attachment shall state that within the developments to which it applies, the electing provider will make unbundled subloops available to its competitors pursuant to this rule. It shall specify the basic terms under which subloops will be offered, and such terms shall be consistent with this rule and any applicable orders of the Commission.

(3) The Electing Provider Attachment may be updated to specify additional developments to which it is applicable. Any such update shall be filed before the electing provider enters into any preferred provider contract with weighted commission provisions relating to any of the additional developments.

(g) A preferred provider may become an exempted provider by filing with the Commission an Exempted Provider Attachment that meets the requirements of subdivisions (1) through (3) below. An exempted provider, within the developments specified in its Exempted Provider Attachment, may enter into preferred provider contracts containing weighted commission provisions and may continue to enforce existing preferred provider contracts containing such provisions.

(1) The Exempted Provider Attachment shall be attached to the exempted provider's Preferred Provider Notice. It shall identify the name and location of each development to which it is applicable.

(2) The Exempted Provider Attachment shall state either (A) that the exempted provider is a local exchange company and is not required by federal law to make subloops available to competitors in any of the developments to which the attachment is applicable, or (B) that the exempted provider is a competing local provider, and if it were a local exchange company, it would not be required by federal law to make subloops available to competitors in any of the developments to which the attachment is applicable.

(3) The Exempted Provider Attachment may be updated to specify additional developments to which it is applicable. Any such update shall be filed before the exempted provider enters into any preferred provider contract with weighted commission provisions relating to any of the additional developments. For each development for which exemption is asserted in an initial or updated Exempted Provider Attachment, the provider shall submit an affidavit, signed by an engineer with direct personal knowledge of the facilities serving the development, that specifies with particularity the provider's factual and legal basis for asserting the exemption.

(4) A local service provider may challenge an Exempted Provider Attachment by filing a petition seeking review of such Attachment with the Commission. In the event of such a challenge, the Public Staff shall investigate such challenge and file its report and recommendations concerning the merits of such challenge within 30 days of the filing of the challenge. The party asserting exemption shall bear the burden of demonstrating entitlement to the exemption by clear and

convincing evidence. Any such challenge shall, to the extent practicable, be given priority on the Commission's docket.

(h) No local service provider may maintain a preferred provider contract in effect in any development unless it has duly filed with the Commission a Preferred Provider Notice that makes reference to the development, together with any applicable Electing Provider Attachment or Exempted Provider Attachment.

(i) Preferred Provider Notices, Electing Provider Attachments and Exempted Provider Attachments shall be subject to the following filing requirements:

(1) Each preferred provider shall file its Preferred Provider Notice, together with any Attachments, in a docket to be designated by the Commission.

(2) The first Preferred Provider Notice filed by a particular preferred provider shall be labeled "Preferred Provider Notice – Version 1." The first updated Preferred Provider Notice filed by such provider shall be labeled "Preferred Provider Notice – Version 2," and subsequent updates shall be numbered sequentially.

(3) Whenever an Electing Provider Attachment or Exempted Provider Attachment is updated, the provider shall file an update of the entire Preferred Provider Notice, including the Attachments, with a new version number, even if the only changes are in one of the Attachments.

(j) When a competing local provider that is an electing provider receives a request from a competitor for subloops in a given development, the parties shall negotiate in good faith. If they are not able to reach agreement, the following requirements shall apply:

(1) The subloops shall be provisioned within the same time period that the local exchange company in whose franchise area the development is located makes subloops available. If no such period exists, such subloops shall be provisioned within seven days.

(2) At any point 60 or more days after the receipt of a bona fide request for subloop interconnection, either party may request the Commission to set a subloop rate for the electing provider.

(3) There is a rebuttable presumption that the appropriate rate for a subloop is the applicable subloop rate of the local exchange company in whose franchise area the development is located. If there is no such rate in existence, then the rebuttably presumptive subloop rate is BellSouth's Zone 1 subloop rate.

(4) The party seeking a departure from the rebuttably presumptive subloop rate shall have the burden of proof to demonstrate that such rate is not just and reasonable.

(5) The Commission will fix the subloop rates for a competing local provider that is an electing provider on a company-wide basis in an initial contested proceeding. If the rate fixed

by the Commission is different from the rate previously being paid by the subloop purchaser in the contested proceeding, a true-up shall be performed.

(k) Every preferred provider, within the development to which its preferred provider contract applies, shall make its service available to competitors for resale. If the preferred provider is a competing local provider, the following requirements shall apply:

(1) Unless the competing local provider and the reseller agree on a different rate, the wholesale discount percentage offered by the competing local provider shall be the same wholesale discount percentage offered by the local exchange company in whose franchise area the development is located. If no such wholesale discount percentage has been determined, the discount percentage established for BellSouth in Docket No. P-140, Sub 50 shall apply.

(2) If either party contends that the discount percentage provided for in subdivision (1) above is inappropriate, it may request the Commission to calculate the discount based specifically on the circumstances of the competing local provider. If the discount percentage fixed by the Commission is different from the percentage previously being paid by the reseller in the contested proceeding, a true-up shall be performed.

(l) In every development where a local service provider has entered into a preferred provider contract containing provisions that are void under subsections (b), (c) or (d) of this rule, the local service provider shall, within 21 days after the effective date of this rule, mail to each of the parties to the preferred provider contract a letter advising such party that certain portions of the contract have been determined to be void. The

EXHIBIT A
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following materials shall be attached to the letter: a copy of the preferred provider contract, with the void provisions conspicuously marked; a copy of this rule; and a copy of the Commission's order adopting this rule.

DOCKET NO. P-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Proposed Assignment of N11 Abbreviated Dialing Code to the North Carolina One Call Center, Inc.	)))	ORDER FINALIZING RATES AND IMPLEMENTATION ON 811 ABBREVIATED DIALING

BY THE COMMISSION: On February 9, 2006, the Commission issued its *Order Designating Use of 811 and Granting Petition* of the North Carolina One Call Center, Inc. (NCOCC) to use the 811 abbreviated dialing code to receive from and transmit to its members notifications of planned excavations. In its Order, the Commission also requested that the following actions be taken by service providers: (1) any company unable to meet an implementation date of July 7, 2006, should so advise the Commission, and any company which is currently using the 811 dialing code should comply with the April 13, 2007, national implementation date; (2) any LEC using its present 211 or 511 rate structure for 811 would not be required to refile cost support; (3) any LEC which had experienced a significant increase in loaded labor rates or intended to propose a new tariff structure for this N11 service, such as ongoing recurring or usage rates, should file a cost study with the Public Staff; and (4) the Public Staff and any party wishing to do so should file comments on all cost studies submitted for consideration for this N11 service. On February 14, 2006, the Commission issued an *Errata Order* in which it stated that the implementation of 811 service, as suggested by the Public Staff, should occur six months after the Commission's decision, which would have been August 7, 2006, rather than July 7, 2006, as stated in its earlier Order.

RELATED FILINGS

On February 21, 2006, BellSouth Telecommunications, Inc. (BellSouth) filed its "Proprietary" cost study with the Commission as directed by the Commission.

Also on February 21, 2006, Verizon filed comments stating that "Verizon will provision 811 abbreviated dialing via an Advanced Intelligent Network (AIN) platform and intends to utilize the same cost structure and tariffed rates as were filed and approved in P-100, Sub 150 for its 511 offering for NCDOT." Verizon stated it did not envision any difficulties in meeting the August 7, 2006 implementation date.

On February 24, 2006, Sprint made an informational filing with the Commission in which it commented upon its current use of the 811 code and "Sprint's intended implementation date of April 13, 2007." In a similar filing on March 8, 2006, the Concord Telephone Company (CTC) stated that it "currently allows the use of the abbreviated dialing code 811 as a way for customers to contact our customer service representatives." CTC commented that it would also meet the April 13, 2007, implementation date.

PUBLIC STAFF'S COMMENTS

On March 7, 2006, the Public Staff filed its comments on BellSouth's cost study noting that Bellsouth's proposed rates for 811 service consisted of two rate elements: a Central Office Activation Charge per Central Office of $170.46 and a Change in Point-to-Number by Subscriber Charge per Central Office of $11.23. The first rate element is charged at the time service is initially established. The second rate element is only charged when a subscriber requests a change in the number to which the 811 call is translated.

The Public Staff commented that the rates proposed by BellSouth for Central Office Activation are approximately 55% higher than similar charges by BellSouth for 211 and 511 services and approximately 10% higher than those proposed by BellSouth for 311 service. The rate proposed by BellSouth for Change in Point-to-Number is lower than that charged by BellSouth for 211 and 511 services, but that rate element will only be applied if the NCOCC decides to change its number.

The Public Staff further commented that BellSouth, as well as any other service provider experiencing a significant increase in loaded labor rates, could as authorized by the Commission, file a cost study with the Public Staff in support of its proposed rates for 811. The Public Staff stated that, in comparing BellSouth's 811 cost study with the 511 cost study filed by BellSouth in 2004 in

Docket No. P-100, Sub 150, it determined that the loaded labor rates for the two work groups identified in the studies had increased by approximately 17% and 43%. Furthermore, the Public Staff stated that, "since the estimated work times in the 811 cost study are either the same or slightly less than the estimated work times in the 511 cost study, it is clear that the increase in loaded labor rates is the basis for the difference in BellSouth's 511 rates and those proposed by BellSouth for 811 service."

However, the Public Staff concluded that, "based on the fact that 811 service is in the Total Pricing Flexibility category of BellSouth's Price Plan, it does not oppose BellSouth's proposed rates for 811 service despite the significant increase in loaded labor rates reflected in BellSouth's cost study, and it therefore recommends that the Commission allow BellSouth's proposed rates for 811 service to become effective."

NCOCC'S REPLY COMMENTS

On March 17, 2006, NCOCC filed reply comments in which it specifically commented on the proposed 811 service rates of BellSouth, Sprint, and Verizon. NCOCC did not make any specific objection to the approval of BellSouth's proposed rates for 811 service.

NCOCC stated that Sprint, in its reply comments, said that its proposed rates for 811 service would be the same as its rates for 311 and 511 services. NCOCC commented that Sprint's proposed rate structure consists of three rate elements: 1) a Central Office Charge of $250.00; 2) an Exclusion Charge of $350.00; and, 3) a Change in Point-to-Number by Subscriber Charge of $50.00. NCOCC stated that "it is neither necessary nor appropriate for the Commission to approve any Exclusion Charge in connection with 811 service," because 811 service "is to be implemented statewide without exclusion of any geographic areas or dialing prefixes."

In commenting on Verizon's proposed 811 service offering, NCOCC stated that Verizon's 211 service consists of two rate elements: 1) an Establishment Charge of $110.00 per Central Office; and, 2) a Change in Point-to-Number Charge of $28.00; and, that Verizon's charges for 511 consist of three rate elements: 1) an Establishment Charge of $168.50 per Central Office; 2) a Central Office Programming Charge of $130.00 per Switch; and, 3) a Change in Point-to-Number Charge of $19.00. NCOCC commented that Verizon should be allowed to only charge two rate components in providing 811 service: 1) an Establishment Charge of $168.50 per Central Office; and, 2) a Change in Point-to-Number Charge of $19.00.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that BellSouth's proposed rates for 811 service should be allowed to become effective as filed. While the Public Staff opined that the cost study to provide 811 service reflects "an increase in loaded labor rates" and that this difference in loaded labor rates "is the basis for the difference in BellSouth's 511 rates and those proposed by BellSouth for 811 service," the Commission notes that the Public Staff provided no further comment as to the reasons for such an increase and ultimately recommended approval. Therefore, the Commission can only reasonably conclude that the cost study filed by BellSouth, while reflecting an increase in loaded labor rates, was indeed reasonable to the Public Staff. In addition, NCOCC did not make a specific objection to BellSouth's proposal. As a result, the Commission authorizes BellSouth to implement its proposed rates for 811 service.

Furthermore, the Commission stated in its *Order Designating Use of 811 and Granting Petition* that LECs could use their existing 211 or 511 rate structure in providing 811 service without having to re-file cost support. As such, any challenge to Sprint's use of its 311 and 511 rate structure (which are identical) is superfluous and has already been rejected. In addition, NCOCC's comment that Sprint should not be allowed to charge an Exclusion Charge of $350.00 "because 811 service is to be implemented statewide without exclusion of any geographic areas or dialing prefixes" is in inapposite for another reason. The Commission understands that NCOCC could only be charged the Exclusion Charge in question if, and only if, NCOCC were to subscribe to this particular rate element. Therefore, Sprint's approved rate structure for 511 service, which includes the rate element of an Exclusion Charge of $350.00, is approved for use in supporting the implementation of 811 service.

Lastly, Verizon stated in its comments that it "intends to utilize the same cost structure and tariffed rates as were filed and approved in P-100, Sub 150 for its 511 offering for NCDOT." Although NCOCC suggested that Verizon's approved three element 511 service rate structure be reduced to a two element rate structure for 811 service, the Commission approves Verizon's use of its previously approved 511 rate structure in support of the 811 service implementation consistent with our prior Order in this proceeding.

Finally, the Commission acknowledges CTC and Sprint's use of the 811 code in their current business operations and their commitment to support the implementation of 811 service by April 13, 2007, which is the national implementation date as established by the Federal Communications Commission's Sixth Report and Order in CC Docket No. 92-105, "The Use of N11 Codes and Other Abbreviated Dialing Arrangements." CTC and Sprint shall begin to provide 811 service by the national implementation date.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of March 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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DOCKET NO. P-100, SUB 159

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Petition of Rural Telephone Companies for Modification Pursuant to 47 USC 251(f)(2)) ORDER OF CLARIFICATION

BY THE COMMISSION: On March 8, 2005, the Commission issued an Order Granting Modification Under Section 251(f)(2) providing, among other things, that the Rural ICOs[1] need not perform TELRIC-based reciprocal compensation studies and establishing an interim compensation mechanism as between the Rural ICOs and the commercial mobile radio service providers (CMRS Providers). The Commission stated that the relief it was granting was to "continue until such time as the FCC shall have rendered its final ruling in CC Docket No. 01-92 concerning intercarrier compensation." The Commission also provided that, "[i]n the meantime, the Rural ICOs should conduct alternate cost studies utilizing the guidelines recommended by the Public Staff in its December 14, 2005, Comments" and that the "interim reciprocal compensation rate for termination by Rural ICOs and CMRS Providers should be $0.015 per minute subject to true-up once a permanent rate is established." The Commission noted that the parties may voluntarily agree to different rates if they are so disposed.

On April 4, 2005, the CMRS Providers[2] filed a Motion for Clarification asking the Commission to affirmatively state the following:

1. The ordered interim rate of $0.015 applies between the Rural ICOs and the CMRS Providers on a symmetrical, reciprocal basis beginning on March 8, 2006. To the extent a CMRS Provider either does not have actual measurement capabilities or opts to utilize factor billing in lieu of actual measurements, the parties will use a 70% mobile-to-land and a 30% land-to-mobile traffic ratio for interim billing purposes.
2. Use of the ordered interim rate of $0.015 between the parties will terminate upon the earlier of (a) the effective date of a Commission-approved voluntary agreement, (b) the effective date of a Commission-approved arbitrated agreement, or (c) the date that the negotiation window under 47 U.S.C Section 252 expires with no request for an arbitration having been filed.
3. If a Rural ICO that receives the $0.015 interim rate does not prepare an alternative cost study during the course of the parties' negotiations and an arbitration is filed, the Rural ICO will cause the preparation of an alternative cost study to be prepared in the arbitration proceeding subject to the procedural schedule established in such proceeding.

The CMRS Providers expressed concern that the Commission's Order had not stated when the interim rate was to become effective, when it expired, and when the Rural ICOs were required to perform an alternative cost study. The CMRS Providers noted that, pursuant to the Federal Communications Commission's (FCC's) *T-Mobile Order* [3], FCC Rule 20.11(e) had been amended to permit local exchange companies such as the Rural ICOs to initiate requests for interconnection with CMRS providers. While it is true that, following the expiration of the Parties' settlement agreement in the Summer of 2005, the Rural ICOs served bona-fide requests for negotiations, they never made

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[1] The "Rural ICOs" consist of Citizens Telephone Company, Ellerbe Telephone Company, MEBTEL, Inc., Town of Pineville d/b/a Pineville Telephone Company, and Randolph Telephone Company.

[2] The "CMRS Providers" consist of New Cingular Wireless PCS, LLC d/b/a Cingular Wireless, Cellco Partnership d/b/a Verizon Wireless on behalf of itself and its affiliates, and Sprint Spectrum LP, as agent for SprintCom, Inc. d/b/a Sprint PCS.

[3] *In the Matter of Developing a Unified Intercarrier Compensation Regime, T-Mobile et al. Petition for Declaratory Ruling Regarding Incumbent LEC Wireless Termination Tariffs,* Declaratory Ruling and Report and Order, CC Docket No. 01-92 (rel. Feb. 24, 2005).

any request to the CMRS Providers for the establishment of interim arrangements pending negotiation and arbitration, choosing rather to file their Petition with the Commission in this docket. The currently applicable federal rules key interim pricing to a request for interconnection, and FCC Rule 51.715(c) explicitly provides that an interim arrangement ceases when a voluntary agreement has been negotiated, an agreement has been arbitrated and approved, or the period for requesting arbitration has passed with no such request. The CMRS Providers stated that, should an arbitration be filed, rates supported by an appropriate cost study will certainly be an open issue before the Commission.

COMMENTS

The Rural ICOs structured their comments as follows: (1) What the effective date of the Interim Reciprocal Compensation Arrangement (IRCA) should be; (2) when the Rural ICO cost study should be performed; and (3) whether the default ratio proposed by the CMRS Providers should be adopted.

With respect to the effective date of the IRCA, the Rural ICOs stated that, as a general rule, they would agree that the default interim reciprocal compensation rate established by the Commission in the Order Granting Modification should become effective once an ILEC or a provider of CMRS makes a *bona fide* request for interconnection under Section 251 of the Act. This does not, however, preclude the parties from mutually agreeing otherwise. In fact, the parties have agreed otherwise, since they had previously agreed that the reciprocal compensation rate ultimately established between them, either through negotiation or arbitration, would apply retroactively from July 1, 2005. As the Commission knows, there was a settlement agreement among various North Carolina independent telephone companies, including the Rural ICOs, and various CMRS providers applicable to indirect traffic routed through those ILECs to third-party intermediary local exchange companies (usually BellSouth or Sprint) which covered the period from January 1, 2004, through May 31, 2005. The termination date was later extended to June 30, 2005 by letter agreement. Section 2 of the letter agreement stated that "any members of the NC Rural ILEC and NC Wireless Group that hereafter enter into a formal interconnection agreement (as a result of either negotiation or arbitration) shall use the final compensation terms of that agreement to perform a 'true-up' back to July 1, 2005, the date on which compensation ceases under this extension of the Settlement Agreement." Clearly, then, the operative effective date for the IRCA is July 1, 2005.

As to when the cost study should be performed, the Rural ICOs submitted that they should not be required to perform a cost study until after an arbitration petition has been filed. No requirement exists under the Act or FCC rules that such a study should be conducted during the pendency of negotiations. The Rural ICOs noted that the CMRS Providers are free initiate an arbitration, which would obligate the Rural ICOs' having to generate a cost study.

As for the default ratio proposed by the CMRS Providers, the Rural ICOs noted that, for many years, the wireless carriers have relied on rural ILECs to record wireless-originated traffic terminated to those ILECs, poll their switches, assemble message records, mediate the message records, store the records, and process the message records for billing. The CMRS Providers have typically used default billing arrangements to estimate the landline-to-mobile minutes for which rural ILECs pay reciprocal compensation to the CMRS Providers. These default billing arrangements often take the form of a traffic ratio, which is an estimated ratio of the number of wireless-to-landline minutes compared to the number of ILEC-to-wireless minutes. The Rural ICOs contended that the CMRS providers want to benefit from reduced reciprocal compensation rates to rural ILECs, bill increased usage to rural ILECs, and yet continue to enjoy the fruits of the ILECs' billing operations. The CMRS providers attempt to negotiate ever more favorable default traffic ratios, knowing that most small ILECs have a limited capability to measure land-to-mobile traffic and thus have no ability to determine what the actual ratio for traffic is. CMRS providers have the capability to record and bill for actual land-to-mobile traffic, just as rural ILECs have the capability to record and bill for mobile-to-land traffic that they terminate. The Rural ICOs therefore contend that, while parties are certainly free to negotiate traffic ratios, it is their view that the interim rate should be applied to traffic actually terminated and that the proposed 70/30 ratio should be rejected.

The Public Staff doubted the underlying need for clarification. In their initial petition, the Rural ICOs sought only to modify the requirement that cost studies be based upon TELRIC principles. The Commission allowed the request but did not further indicate that the Rural ICOs were permitted to modify the time period for which interim rates apply or to delay the production of a cost study. In any event, it appears that the CMRS Providers may be seeking to impose a condition on the availability of the interim reciprocal compensation rate that does not comply with FCC rules. In their Motion, the CMRS Providers wanted an interim rate of $0.015 to be applied on a symmetrical, reciprocal basis beginning on March 8, 2006, the date of the Commission's Order. But FCC Rule 51.715(a) provides that the interim rates are applicable immediately upon request when an interconnection arrangement providing for the transport and termination of traffic does not exist. The Public Staff, not being privy to the negotiations between the parties, is unable to state when negotiations actually began. In the original Petition, the Rural ICOs claim to have been actively negotiating with the CMRS Providers since early 2005.[1] Thus, it appears that the CMRS Providers are requesting the Commission to designate a date for initiating the interim rate that is unrelated to the time that interconnection was requested.

As for the 70/30 default ratio, the Public Staff observed that the CMRS Providers provided no basis for such a factor, nor established the need for such a factor. The Public Staff therefore has no position as to the appropriateness of using the proposed default ratio, but this matter is a fit subject for negotiation between the parties.

While doubting the need for clarification, the Public Staff stated it did not object to the following clarifications addressing the CMRS Providers' concerns and not conflicting with FCC rules:

1. The ordered interim rate of $0.015 applies between a Rural ICO and the CMRS Provider parties on a symmetrical, reciprocal basis, beginning when the Rural ICO submitted a request for negotiation, unless the parties mutually agree on a different date.
2. Use of the ordered rate of $0.015 between the parties will terminate upon the earlier of (i) the effective date of a Commission-approved voluntary agreement, (ii) the effective date of a Commission-approved arbitrated agreement, or (iii) the date that the negotiation window under Section 252 expires with no request for arbitration having been filed; and

[1] In the Rural ICOs' Petition Concerning TELRIC Studies, on page 2, paragraph 5, it is simply stated: "Since at least early 2005, the Rural ICOs and various CMRS providers have been in active negotiations for a follow-on agreement to the Settlement Agreement...."

3. If a Rural ICO that receives the $0.015 interim rate does not prepare an alternative cost study in accordance with the Commission's March 8th Order during the course of the parties' negotiations and a petition for arbitration is subsequently filed, the Rural ICO will cause an alternative cost study to be prepared in the arbitration proceeding subject to the schedule set forth by the Commission in that arbitration proceeding.

CMRS PROVIDER REPLY COMMENTS

CMRS Providers led off their reply comments by noting that they expected that their recommendations regarding how and when the interim rate should be implemented to be controversial. They also stated that they were agreeable to a 75/25 traffic ratio, instead of the originally proposed 70/30 traffic ratio.

More specifically, on the question of the effective date of the interim rate, the CMRS Providers argued that, while the Public Staff correctly cited to FCC Rule 51.715(a) for the proposition that the interim rule is applicable upon request for interconnection, the Public Staff was not correct to equate a request for an interim arrangement with a party's initial request for negotiations. Likewise, the Rural ICOs are incorrect in seeking the interim rate true-up to be effective on July 6, 2005, pursuant to a letter agreement that expressly provides for a true-up to be subject to "final compensation terms" of a negotiated or arbitrated rate (rather than an interim rate) and which bears no relationship to any reading of FCC Rule 51.715.

In short, the CMRS Providers believe that the use of any date other than the March 8, 2006, date is inconsistent with the FCC Rule 51.715, taken in its entirety. In support of this proposition, the CMRS Providers pointed out that FCC Rule 51.715(a) provides that, "[u]pon request from a telecommunications carrier without an existing interconnection arrangement...the [non-requesting] carrier shall provide transport and termination of telecommunications traffic immediately under the interim arrangement." Subsection (a)(2) of that rule further provides that "[a] telecommunications carrier may take advantage of such arrangement only after it has requested negotiation...." And FCC Rule 51.715(b) provides that, "[u]pon receipt of a request as described in paragraph (a) of this section," an interim arrangement is to be established without unreasonable delay. The CMRS Providers argued that the FCC's rationale for an interim arrangement requirement emanated from concern that carriers seeking interconnection would be at different stage of market entry readiness. FCC Rule 51.715 is referring to two different types of requests—one being a request for negotiations and the other being a request for interim arrangements after a request for negotiations has been made.

Certainly a requesting carrier can incorporate an express request for interim arrangements within the same initial letter that also requests negotiations, but no Rural ICO at this point has made any request for interim arrangements to the CMRS Providers. Even so, in the interests of fair treatment, the CMRS Providers are agreeable to construing the Commission's Order as a request from the Rural ICOs to implement an interim arrangement, subject to true-up. The CMRS Providers also argued that this would avoid the imposition of multiple true-ups clearly not contemplated by the FCC rules.

As for traffic factors, the CMRS Providers pointed out that traffic factors were utilized in the Settlement Agreement (a copy of which the CMRS Providers attached to their filing as Exhibit 1). Despite the Rural ICOs' statements, it is not true that all CMRS Providers have the switching and billing system capabilities that enable real-time switch measurement and billing generation.

Moreover, there is currently no terminating Rural ICO or CMRS Provider billing system that can jurisdictionalize a call to or from a CMRS Provider on a real-time basis; and, in the case of indirect interconnection—which is the predominant type of interconnection between the Rural ICOs and the CMRS Providers—a Rural ICO billing system does not generally perform any (much less automated) cross-comparisons of terminating CMRS call detail records to any terminating IXC call detail records, which can result in double-billing by the Rural ICO for the same call if it attempts to use its own billing system instead of the transit providers' records. The CMRS Providers also noted that the use of billing factors is a common industry practice and that the factors mutually benefit both parties by avoiding disputes over individual bills.

As for the date on which the interim rate of $0.015 should expire, the CMRS Providers noted that the Public Staff did not object to their proposed clarification, and the Rural ICOs did not address the question. Hence, the CMRS Providers suggested clarification should be approved.

As to when the cost study is to be performed, the CMRS Providers denied that their clarification sought to impose an obligation on the Rural ICOs to prepare a pre-arbitration cost study. While they believe that such preparation would go a long way to advance rate negotiations, the CMRS Providers are not requesting that the Commission order pre-arbitration cost studies.

Accordingly, the CMRS Providers reiterated their proposed clarifications from their original Motion, with the exception that a 75/25 traffic factor be used instead of 70/30.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

This matter presents essentially three questions. The first and most complicated question has to do with when the interim rate of $0.015 should come into play and when it should end. The second has to do with whether a billing factor should be authorized. The third has to do with when the Rural ICOs must prepare their non-TELRIC cost studies.

Timing of Interim Rate. As noted above, the first question is the most vexing. The parties have managed to come up with three separate answers. The CMRS Providers say that payment of the interim rate should begin on March 8, 2006, the date of the Commission's Order Granting Modification. The Rural ICOs say that it should begin on July 1, 2005, based upon language in the letter agreement that extended the Settlement Agreement to June 30, 2005. The Public Staff says it should begin when negotiations started in "early 2005." The Public Staff is not sure of the precise date upon which negotiations began because that date has never been stated for the record.

Philosophically, all the parties appear to agree that FCC Rule 51.715 should control, but determining how the precise terms of that rule apply to the present case and square with the positions of the parties is something of a mystery. In the *T-Mobile Order*, issued on February 24, 2005, the FCC propounded a new FCC Rule 20.11(f), which, for the first, time enabled ILECs to *initiate* the interconnection and arbitration process with CMRS Providers. This provision reads as follows: "An incumbent local exchange carrier may request interconnection from a commercial mobile radio service provider and invoke the negotiation and arbitration procedures in section 252 of the Act. A commercial mobile radio service provider receiving a request for interconnection must negotiate in good faith and must, if requested, submit to arbitration by the state commission. Once a request for interconnection is made, the interim transport and termination pricing described in [FCC Rule] 51.715 shall apply."

FCC Rule 51.715 is, of course, consistent with this rule. FCC Rule 51.715(a) requires the establishment of an "interim arrangement" upon such request from a telecommunications carrier, but, under FCC Rule 51.715(a)(2), it can only do so after it has requested negotiation—i.e., a negotiation under Section 252 leading either to a voluntary agreement or arbitration. The FCC contemplates that requests for interconnection and requests for interim arrangements will be tied together.

In the instant case, this is a bit of a square peg in a round hole, judging from the positions of the parties. As noted, the CMRS Providers advocate a March 8, 2006, beginning date, but this has nothing to do with any date on which a request for negotiations leading to agreement or arbitration has been made. Indeed, the CMRS Providers admit that this date is to be *construed* this way—out of "fairness—without actually being this way. The Public Staff advocates "early 2005" on the basis that this is at least the general time frame in which the Rural ICOs indicate that they have been "negotiating" with the CMRS Providers. However, the date for requesting arbitration as a result of those negotiations has long since passed. Two additional complications are that there is no evidence in the record as to whether the "negotiations" began before or after the *T-Mobile Order* was issued on February 24, 2005 and that pushing the beginning date back to early 2005 overlaps with the period ending June 30, 2005, since the Rural ICOs were presumably receiving compensation under the Settlement Agreement and its extension up until that time. Finally, the Rural ICOs advocate for July 1, 2005. This is the date the Settlement Agreement, as extended, expired. The Rural ICOs rely on language in the letter agreement, which extended the Settlement Agreement to June 30, 2005, to the effect that there should be a true-up back to July 1, 2005, if the parties have "hereafter" entered into a formal interconnection agreement. This, too, is imperfect because this date does not comport with a strict reading of the FCC Rule 51.715 keying an interim arrangement to the request for interconnection or with the literal language of the Settlement Agreement, which refers to an agreement on final compensation terms.

Nevertheless, of all the alternatives presented, the date proposed by the Rural ICOs is the least objectionable and the most just. It is the least objectionable because the letter agreement at least shows an intent under a negotiated agreement of the parties that there would be a true-up back to July 1, 2005, as well as an understanding by the parties that there would be either a negotiated or arbitrated agreement in the future. It is the most just because it simply continues compensation *at the same rate* as in the Settlement Agreement from the point where the Settlement Agreement left off. The parties have been providing services for each other for which they are presumably not being paid in full or at all, and that result is not just.

The Commission does not believe, however, that payment of the interim rate should continue indefinitely without progress toward an interconnection agreement.. Either the Rural ICOs or the CMRS Providers must initiate a formal Section 252 negotiation within 30 days of the issuance of this Order so this matter can be resolved with finality. Otherwise, the payment of the interim rate is suspended if such negotiation is not initiated within 30 days and will be resumed only upon the initiation of such negotiation.

Fortunately, there was no substantial disagreement among the parties as to when the interim rate should otherwise end. It should end when the Commission either approves a negotiated rate, has finally arbitrated one, or the negotiation window has expired without a request for arbitration.

Billing Factor. The CMRS Providers sought clarification that the use of billing factors would be authorized to the extent that they do not have actual measurement capabilities or opt to utilize a billing factor in lieu of actual measurements. The CMRS Providers originally sought a 70% mobile-to-land and a 30% land-to-mobile traffic ratio for interim billing purposes, but in their Reply Comments revised the ratio to 75 to 25, which was the ratio used in the Settlement Agreement. The Public Staff did not believe that the CMRS Providers had set forth a basis for a traffic factor, nor sufficiently proved their need for it. Such ratios are, however, a fit subject for negotiation. The Rural ICOs took umbrage at the CMRS proposal and expressed their view that the interim rate should be applied to traffic actually terminated.

The Commission believes, as a general matter, that billing ought to be based on actual measurement rather than traffic factors to the extent feasible, but the Commission is also convinced that there may be circumstances pertaining to traffic between the CMRS Providers and the Rural ICOs where actual measurements are *not* possible. In order to provide for orderly compensation in such circumstances, it is advisable for the parties be required to resort to traffic factors when actual measurements are not feasible. The most reasonable ratio is that set out in Section 2.02 of the Settlement Agreement—namely, 75/25—and the most reasonable methodological context is set out in Section 2.03.

Preparation of cost studies. The CMRS Providers sought clarification of when the Rural ICOs were expected to prepare their non-TELRIC cost studies, but they later acknowledged that they did not expect the Rural ICOs to have to do so until an arbitration has commenced. This is the correct answer. The Rural ICOs are not obliged to perform their cost studies until an arbitration has commenced and in accordance with the Commission's procedural order. However, the CMRS Providers have noted the potential value of earlier cost studies in advancing rate negotiations. The Commission urges the Rural ICOs to consider this perspective in choosing when to prepare their cost studies.

IT IS, THEREFORE, ORDERED as follows:

1. That the ordered interim rate of $0.015 shall apply between the Rural ICOs and the CMRS Providers on a symmetrical, reciprocal basis beginning on July 1, 2005.

2. That use of the ordered rate of $0.015 between the Rural ICOs and the CMRS Providers shall terminate upon the earlier of (a) the effective date of a Commission-approved voluntary agreement, (b) the effective date of a Commission-approved arbitrated agreement, or (c) the date the negotiation window under Section 252 of the Act expires with no request for arbitration having been filed.

3. That the Rural ICOs or the CMRS Providers shall initiate a Section 252 negotiation within 30 days from the issuance of this Order. If the Rural ICOs or CMRS Providers do not do so, the obligation to pay the interim rate shall be suspended pending the initiation of such a negotiation. The party initiating a Section 252 negotiation shall file immediately notice of same with the Commission.

4. That the Rural ICOs shall prepare alternative cost studies subject to a schedule set forth in such arbitration proceeding as the Commission may hold but are encouraged to prepare such studies earlier in order to expedite negotiations.

5. That, to the extent actual traffic measurements are not feasible, the parties shall utilize the traffic factor and methodology set forth in Sections 2.02 and 2.03 of the Settlement Agreement.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of May, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DI053106.01

DOCKET NO. P-100, SUB 162

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Rulemaking on Discontinuation and/or Reduction	)	ORDER PROMULGATING
of Telecommunications Services	)	DISCONNECTION RULES

BY THE COMMISSION: On November 22, 2005, the Commission issued an interim rule in Docket Nos. P-821, Sub 2 and P-55, Sub 1596, authorizing disconnection with due notice of GTC Telecom Corporation by BellSouth Telecommunications, Inc. The interim rules, moreover, were to have general applicability and remain in effect pending further order. The interim rules provided as follows:

(a) An ILEC [incumbent local exchange carrier] or other underlying provider shall not terminate service to CLPs [competing local providers] unless such ILEC or other underlying provider has provided at least 14 days' notice prior to termination of service to the CLP and the Commission.

(b) Upon receipt of the Notice at the Commission, the Public Staff shall forthwith investigate the proposed termination of service and shall file recommendations with the Commission concerning whether adequate notice has been given by the CLP and whether there is good cause for such termination.

(c) If the Public Staff recommends that good cause for such termination exists, the Commission may authorize such disconnection, subject, however, to the provisions that the CLP shall have first given adequate notice to its end users, but, if the CLP has not done so or is unwilling to do so, then the ILEC or other underlying carrier shall have done so.

On December 19, 2005, Verizon South, Inc. (Verizon) filed a Motion for Reconsideration in the above dockets asking that the Commission vacate the interim rules. On February 28, 2006, the Public Staff filed proposed permanent rules and a response to Verizon's Motion for Reconsideration. On March 2, 2006, the Commission issued an Order Establishing Generic Docket and Denying Motion for Reconsideration. The Commission solicited comments on the Public Staff's proposed rules from interested parties and reply comments from the Public Staff, while permitting the interim rules to remain in place.

COMMENTS

Time Warner Telecom of North Carolina and US LEC of North Carolina, Inc. (CLP Group) stated that they supported the Commission's goal of an orderly procedure to inform telecommunications customers that their local exchange service may be discontinued or reduced but argued that the proposed rules should not operate to frustrate the negotiated terms of interconnection agreements (ICAs) between the LECs and the CLPs that provide dispute resolution mechanisms or otherwise detail the terms of service disconnection. Second, the CLP Group also argued that the dispute resolution and disconnection terms, to the extent that they exceed the baseline measures set forth in the proposed rules, should continue to govern the relationship between service providers.

Finally, the CLP Group proposed that the Commission adopt a rule prohibiting LECs from (1) disconnecting CLPs for defaults occurring in another state and (2) disconnecting one CLP for another CLP's failure to pay pursuant to an entirely separate ICA, even if the two CLPs are affiliated. To permit CLPs to be disconnected in such circumstances would be anti-competitive and frustrate the purpose of this proceeding, which is to ensure that consumers maintain local exchange service.

The Alliance of North Carolina Independent Telephone Companies, BellSouth Telecommunications, Inc., ALLTEL Communications, Inc., Carolina Telephone and Telegraph Company, Central Telephone Company, Randolph Telephone Company, TDS Telecom, and Verizon (LEC Group) generally praised the efforts of the Commission to establish rules applicable when a CLP exits a local market. This most commonly occurs when a CLP orders services from an ILEC but fails to pay for those services, resulting in the ILEC taking actions that may result in the interruption of the CLP's end-users' services. In some cases, end-users may receive little or no notice of the impending disconnection. The LEC Group stated that its members have acted responsibly with respect to such disconnection, but CLPs must also be responsible and meet their obligations as well.

The LEC Group identified its changes to the proposed rules. They also provided a red-lined version of those changes attached to their filing. Those changes consist of the following:

Rule 21-4(d). Change 45-days notice requirement to 30 days. ICAs currently in place provide for a 30-day notice period for CLP disconnection by the underlying carrier. A 30-day requirement would assist in minimizing bad debt because during the additional 15 days a CLP could continue to incur debt, and a longer time frame increases the length of time in which an ILEC must provide service for which it is unlikely to be paid. A 30-day notice period is consistent with the time frame provided in other states.

Rule 21-4(i) and (j). Change 14-day to 7 day notice. The shorter time frame would protect the ILECs from additional bad debt. It is adequate, especially since the Commission can extend the deadline for good cause shown. It is also consistent with the notification window provided in neighboring states.

Rule 21-4(i). Commission notification of CLP end users versus ILEC notification. ILECs should not be in the position of having to notify CLP end users of the need to select a new provider. Arguably, this could confer a competitive advantage on the ILECs. Since the ILECs cannot discuss any issues involving repair, ordering service, due date, etc. with CLP end users, it would seem more appropriate for the Commission to make such contact with end users.

Other. The CLP should be held responsible for reimbursing any expense incurred in notifying its end users of the pending disconnection of their local service as it is the CLP's failure to fulfill its duties that led to these costs. Should a CLP be unwilling or unable to provide reimbursement, a mechanism should be established to ensure adequate funds for this purpose. Accordingly, as a condition for certification, all new CLPs should file with the Commission a corporate surety bond or irrevocable letter of credit in the amount of $5,000 to ensure that such funds are available. In addition, CLPs that are currently certified should be required to file the required surety bond or irrevocable letter of credit with the Commission by no later than October 1, 2006 in order to retain certification. CLPs owning and operating equipment facilities in North Carolina with a value of more than $5 million should be exempt from this requirement. The proposals of the LEC Group are consistent with rules and practices adopted in Tennessee and South Carolina.

PUBLIC STAFF REPLY COMMENTS

The Public Staff responded to the comments of both the CLP Group and the LEC Group and set out further revisions to its proposed rules.

With respect to the CLP Group, the Public Staff stated that it did not disagree with their contention that, when an ICA includes provisions regarding the disconnection of service, those provisions should normally be controlling. However, the Public Staff doubted the necessity of the CLP Group's amendment. Under Rule R21-4 as proposed by the Public Staff, provisions relating to disconnection are not prohibited from being included in ICAs and will not be superseded unless they conflict with the rule as, for example, by providing for less notice of disconnection to the CLP or its customers than the proposed rule requires. The Public Staff, on the other hand, stated that it agreed with the CLP Group that a CLP should not be disconnected in North Carolina for defaults occurring in other states, nor should a LEC be permitted to disconnect service to a CLP because of a default committed by another CLP that is unaffiliated with the CLP to be disconnected and is served under a different ICA. However, if a LEC and CLP have agreed that a CLP may be disconnected for a default committed by another CLP with which it is affiliated, and the default occurs in North Carolina, the Public Staff believes the disconnection should be allowed to proceed. The Public Staff stated that it has added a new subsection (a), together with a new subsection (c)(2) [appearing as subsection (d)(2) because of the insertion of the new subsection (a)] to its proposed rule to incorporate those suggestions of the CLP Group with which it does agree.

With respect to the LEC Group, the Public Staff agreed with some of the comments and disagreed with others. The Public Staff did not agree with the LEC Group's proposal to allow disconnection of service within only 30 days after a LEC's initial filing with the Commission. During the 45-day notice period provided for in the Public Staff's proposal, the Public Staff must investigate the proposed termination of service and try to resolve the problem between the LEC and the CLP if possible. The Commission will need time to review the matter and determine whether good cause exists for the termination of service. A 45-day notice period is reasonable and not excessive.

Likewise, the Public Staff believed that a 14-day period between notice to customers and disconnection of service is appropriate and cannot be safely cut in half as proposed by the LEC Group. A 14-day period is necessary to warn customers of their impending loss of service and to enable them to acquire a new service provider. Also, this time period is consistent with Commission Rule R17-2(q) requiring CLPs to provide at least 14 days' notice prior to disconnecting service to a customer. It also gives the CLP a final opportunity to settle its debt once the Commission has determined that the proposed discontinuance is appropriate.

The Public Staff opposed the LEC Group's proposal to require the Commission to take responsibility for notifying customers of the termination of their service when the CLP fails to provide adequate notice. Certainly, CLPs should bear the primary responsibility for contacting their customers and providing notice of termination, and the Public Staff's proposed rules provide for this. However, the underlying carrier is in the best position to contact the CLP's customers if it should come to that. The underlying carrier's efforts to contact customers cannot be considered anticompetitive, as they would be conducted pursuant to Commission order.

While the Public Staff agreed with the LEC Group that, when a CLP fails to notify its customers of pending disconnection, it should be held responsible for any reasonable expense incurred by the LEC in contacting customers for this purpose, the Public Staff did not believe that CLPs should be required to file a bond to fund customer notices. The Public Staff pointed out that requiring a bond could be viewed as an impediment to entering the market in North Carolina and might run afoul of Section 253 of the Telecommunications Act of 1996 (the Act) or at the very least be seen as inconsistent with the purpose of that section. Moreover, some CLPs have been disconnected by more than one underlying carrier. This situation could result in underlying carriers racing to discontinue service in order not to be left out of the bond proceeds. Notably, since January 1, 2004, only five CLPs have been brought before the Commission for failure to pay underlying carriers. This suggests that the potential financial impact on underlying carriers would be minimal.

The Public Staff stated that it had carefully reviewed the changes that were included in the LEC Group's redraft of the proposed rules but which were not explained in the accompanying comments. The changes with which the Public Staff agreed have been incorporated into the Public Staff's revised version of the proposed rules. Some of these matters have been technical and clarifying. The Public Staff objected to the changes that the LEC Group proposed with respect to notice to be sent to the customers under proposed Rules R21-4(g)(1) and (2). The LEC Group's proposed changes may result in misunderstanding or confusion. It is essential that all customers be clearly put on notice that their service is scheduled for termination and that they need to locate a new local service provider.

The Public Staff noted that the LEC Group's redraft of the proposed rules included a new subsection (d) of proposed Rule R21-3. This new subsection, although not entirely clear, is apparently intended to require that carriers in bankruptcy provide the Commission with a list of their customers. While recognizing that such a list should be provided in the event of termination of service to, or by, the carrier, it appears that the new proposed rules would cover filing for reorganization under Chapter 11 of the Bankruptcy Code, as well as filings for liquidation under Chapter 7. A Chapter 11 CLP, which would expect to emerge from bankruptcy, would strongly object to making a list of its customers publicly available. The Public Staff therefore has added a new subsection (1) to proposed Rule R21-4(g) requiring that a customer list be provided to the Commission by a CLP threatened with disconnection by its underlying carrier, rather than including such a provision in proposed Rule R21-3.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that good cause exists to promulgate Rule R21-1 *et seq.* as proposed by the Public Staff on February 28, 2006, and revised by the Public Staff on June 13, 2006, with the exception that the minimum disconnection time period should be reduced from 45 days to 30 days as set out in Rule R21-4(e) as it appears in Appendix A. These rules represent a codification and extension of the interim rules adopted on November 22, 2005, regarding discontinuance and reduction of telecommunications service by LECs and CLPs.[1] The interim rules themselves were based on informal practices and principles that had proved their usefulness and equity over time.

The subject matter of these rules deals mainly with the important question of how to balance the right of the underlying carriers to terminate wholesale service to CLPs who cannot or will not pay their bills with the position and rights of innocent end-users. It is universally agreed that such end-users should receive timely notice that termination is imminent so as to have a meaningful opportunity to obtain alternate service. Difficulties arise, however, when such customers have not or will not receive notice and assistance from the CLPs involved, despite the legal requirement that the CLPs do so.

While generally supportive of the effort to codify the rules, the LEC Group wanted shorter notice periods and compensation for expenses in notifying end-users if required to do so. The LEC Group also proposed Commission notification of end-users as a default alternative to the underlying carrier's doing so.

The Commission agrees with the LEC Group that the proposed minimum disconnection time period should be reduced from 45 days to 30 days, noting, however, that the 30-day time period can be extended by the Commission for good cause. Other time frames as proposed by the Public Staff should not be changed.

The Commission does not agree with the LEC Group that the Commission should provide notice of disconnection to CLP end-users if the CLP is unable or unwilling to do so. Such an approach is impractical since, among other reasons, the Commission lacks the resources and the subscriber information to do so. The Commission would have to obtain the information from others, thereby introducing delays. Further delays would result because the Commission would not have recourse to one of the more efficient and timely methods to give notice – placing a phone message on the end-user's line – but would have to resort exclusively to the United States mail. The ILECs, by contrast, are in a much better position to contact the CLP's end-users on a timely basis should that eventuality become necessary.

Of course, the ILECs would incur expenses in contacting CLP customers. The Public Staff was sympathetic to the arguments made by the LEC Group that ILECs should be able to recover reasonable expenses in contacting customers but pointed to the practical difficulties of a bond approach advocated by the LEC Group. The Commission likewise is sympathetic to the recovery of such expenses but is inclined to believe that a better mechanism would be for the parties to negotiate reasonable deposit requirements in interconnection agreements.

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[1] The rules also address previously unaddressed topics such as filing requirements for LECs or CLPs in bankruptcy. (Rule R21-3).

In summary, the Commission believes that the rules advocated by the Public Staff strike a good balance of the interests of the ILECs, the CLPs, and customers. Accordingly, for the reasons as generally stated by the Public Staff, the Commission concludes that Rule R21-1 *et seq.* should be promulgated as set out in Appendix A hereto, effective immediately and supplanting the interim rules.

IT IS, THEREFORE, SO ORDERED.
This the 30th day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DI083006.01

Chair Jo Anne Sanford did not participate.
Commissioner James Y. Kerr, II dissented.

APPENDIX A
Page 1 of 6

DISCONTINUANCE OR REDUCTION OF TELECOMMUNICATIONS SERVICES

R21-1 APPLICATION

(a) This rule governs both the complete cessation of telephone operations and the discontinuance or reduction of telephone service by local exchange companies (LECs) and competing local providers (CLPs), as defined in Commission Rule R17-1. It does not apply to disconnection of service to an individual customer for nonpayment in accordance with Chapter 12 of the Commission's Rules.

(b) This rule is directed toward the discontinuance or reduction of service by, or termination of service to, carriers whose customers are end users. In the event of a request for discontinuance or reduction of service by, or termination of service to, a carrier that provides both wholesale and retail service, or exclusively wholesale service, the Commission shall address such request in such manner as may be just, and shall, to the greatest possible extent, ensure that all affected parties, including but not limited to wholesale customers and end users, are afforded at least as much advance notice of cessation of service as provided for in these rules. Rule R21-3 is applicable to all bankruptcy filings, regardless of whether the bankrupt carrier provides wholesale service, retail service, or both.

R21-2 DISCONTINUANCE OR REDUCTION OF TELECOMMUNICATIONS SERVICE BY LECs AND CLPs

(a) A LEC or CLP intending to cease operations or to discontinue or reduce the provision of telecommunications service in North Carolina shall seek permission from this Commission to abandon or reduce service in accordance with G.S. 62-118. The LEC or CLP shall file a petition for authority to discontinue or reduce service with the Commission not less than forty-five (45) days prior to the date of discontinuance or reduction of telecommunications service. The petition shall include, at a minimum:

(1) For each service offering to be discontinued, a description of the service offering, the number of customers that will be affected by the discontinuance, identification of any customers affected by the discontinuance that are themselves telecommunications carriers, identification of the underlying carrier(s), if any, for the offering, and the proposed date of discontinuance;

(2) A description of customer notification efforts and copies of the written notice(s) sent or proposed to be sent to customers. If the notice is not consistent with the requirements of R21-4(g), the petition shall state why the proposed notice is sufficient;

(3) A full explanation of the reasons for the proposed service discontinuance or reduction;

(4) Details of any plan to migrate customers to other carriers and identification of the carrier(s) to whom the service(s) are to be migrated. If no migration plan is provided, the petition shall state why a plan is not necessary; and

(5) If all North Carolina service offerings are being discontinued, a request for cancellation of the certificate(s) of public convenience and necessity of the LEC or CLP upon the approval of discontinuance. If cancellation of the certificate(s) is not requested, the carrier shall provide a concise statement explaining why the Commission should not cancel the certificate(s).

(b) Existing customers of the service(s) to be discontinued must be provided written notice sufficiently in advance of service reduction or discontinuance to allow an alternate service to be established without the customer incurring a lapse in service, and, in any event, not less than fourteen (14) days prior to the proposed service reduction or disconnection.

(c) In the event of discontinuance or reduction of local exchange service, the LEC or CLP shall include in customer notices and on its website a toll-free number that customers may call with inquiries prior to such discontinuance or reduction of local exchange service. Knowledgeable service representatives shall be available at the toll-free number to answer customers' questions.

(d) The Commission shall determine if sufficient notice has been provided or is proposed to be provided to customers and shall prescribe any additional notice or other requirements, as it deems necessary in the public interest.

(e) No discontinuance or reduction of telecommunications service shall be implemented until the Commission has ruled on the petition, issued an order, and determined that adequate notice has been provided to end user customers.

(f) Within seven (7) days following Commission approval of the discontinuance or reduction, the LEC or CLP shall post on its website, for its customers and other carriers, information that will assist in the orderly migration of customers.

(g) Unless the LEC or CLP has already arranged for all of the services which it proposes to discontinue to be transferred to another carrier, the LEC or CLP shall file with the Commission, within seven (7) days of receiving Commission approval of the discontinuance or reduction, a spreadsheet containing a list of billing names, addresses, and telephone numbers (or circuit numbers for non-switched services) for all customers affected by the discontinuation, except those with non-published numbers. For customers with non-published listings, the LEC or CLP shall provide only their billing names, addresses, and the NPA-NXX of their telephone numbers. The list shall specifically identify those end user customers who are public utilities, governmental agencies, inmate facilities or hospitals. If the LEC or CLP is facilities-based, the list shall also include circuit IDs, cable pair identification and a statement that the LEC or

CLP will fully cooperate in the transfer of numbers to other providers through the Number Portability database. This list shall only be used to facilitate the transfer of the end user customers to their new service providers.

R21-3 BANKRUPTCY

(a) A LEC or CLP that is the subject of a petition under any provision of the federal Bankruptcy Code shall immediately file with the Commission the following materials and shall keep them updated through further filings with the Commission throughout the duration of the bankruptcy proceeding:

(1) A complete copy of the bankruptcy petition;

(2) The name, address, and telephone number of any trustee in its bankruptcy proceeding; and

(3) The names, addresses and telephone numbers of all attorneys representing the LEC or CLP in its bankruptcy proceeding.

(b) During the pendency of the bankruptcy proceeding, the LEC or CLP shall file with the Commission, immediately upon their being filed with or issued by the Bankruptcy Court, the following materials:

(1) Copies of all orders or rulings of the Bankruptcy Court that have an impact on the provision of North Carolina telecommunications service by the LEC or CLP, or on the discontinuance or reduction of such service;

(2) Copies of any plan under Chapter 11 or any other chapter of the Bankruptcy Code that is approved by the Bankruptcy Court or is formally submitted to creditors for their approval or disapproval; and

(3) Copies of any other documents filed with or issued by the Bankruptcy Court that the Commission directs the LEC or CLP to file.

(c) Nothing contained in this Rule is intended to interfere with the jurisdiction or authority of the Bankruptcy Court under the Bankruptcy Code.

R21-4 TERMINATION OF SERVICE TO CLPs BY UNDERLYING CARRIERS

(a) An underlying carrier shall not terminate service to a CLP except as authorized under its interconnection agreement with the CLP; provided, however, that an underlying carrier shall not under any circumstances terminate service to a CLP because of (i) a default by a third party not affiliated with the CLP or (ii) a default occurring outside North Carolina that does not

constitute failure to pay for North Carolina services. For good cause shown, the Commission may authorize an underlying carrier to terminate service to a CLP for failure to pay for services provided in another state, if termination under such circumstances is expressly provided for in the parties' interconnection agreement.

(b) In the case of billing disputes between a CLP and an underlying carrier, the parties shall make a good faith effort to work with each other in determining what portion, if any, of the bill for resale, unbundled network elements, or other services provided by the underlying carrier to the CLP is disputed and which portion is undisputed. The underlying carrier shall work with the CLP to resolve the billing dispute and arrange for payment of the outstanding charges, pursuant to the interconnection agreement between the underlying carrier and the CLP.

(c) In the event that the underlying carrier intends to cease providing service to the CLP for nonpayment or any other reason, it shall send to the CLP a notice of intent to disconnect or deny services to the CLP pursuant to the current interconnection agreement between the carriers. A copy of the notice(s) shall be filed with the Commission.

(d) The underlying carrier shall state the following in the notice:

(1) The name, address and account number of the CLP;

(2) A plain statement of the grounds upon which the right to disconnect or deny is founded, including the total amount owed, the non-disputed amount owed, the disputed amount owed, and the amount required to be paid to avoid interruption of service. If the underlying carrier provides service to the CLP in North Carolina and also in one or more other states, the portions of these amounts applicable to North Carolina services shall be stated separately; and

(3) The exact date and time or range of dates and times the underlying carrier seeks to have service discontinued.

(e) The underlying carrier shall not disconnect or deny service to the CLP prior to the date and time (or range of dates and times) given on the notice of intent to terminate. In no case shall disconnection be effected less than thirty (30) days from the later of the date of mailing of the notice of intent or the filing of the notice with the Commission. If the last day of the thirty (30) day period falls on a Saturday, Sunday or legal holiday, the notice period will expire at the close of the underlying carrier's next business day. In order to ensure that the interests of customers are adequately protected, the Commission may issue directives to underlying carriers and CLPs to effectuate the intent of this Rule.

(f) The underlying carrier shall make its best efforts through coordination and timely attention to change requests from end users and other carriers involved in the services subject to discontinuation to assist in the orderly migration of customers. The underlying carrier and the CLP being disconnected shall provide the Public Staff, upon request, with the status of the customer conversions, including, to the extent available to them, the Local Service Request dates, Firm Order Confirmation dates, and Actual Installation dates.

(g) Upon the filing of the underlying carrier's notice of intent with the Commission, the Public Staff shall forthwith investigate the proposed termination of service and shall file a recommendation with the Commission concerning whether adequate notice has been or is proposed to be given by the CLP.

(h) At least fourteen (14) days before the date specified for termination, if the notice of termination has not been withdrawn and the Commission has not found the proposed termination to be without good cause, the CLP shall:

(1) Provide the Commission with a complete list of all customers being served by the carrier, including the specific customer information referenced in Commission Rule R21-2(g); and

(2) Notify all its affected customers, by direct mailing, of the proposed termination. The CLP shall provide this notice even if it anticipates resolving its dispute with the underlying carrier and even if it contends that the proposed termination is without good cause. The notice to the CLP's customers shall contain the following information in easily legible type:

(i) A clear explanation that service to the customer is being terminated by (name of carrier);

(ii) The date on which the service will be terminated;

(iii) A statement that the customer must make arrangements with an alternate carrier to continue receiving local service;

(iv) If basic local exchange service is to be discontinued, a statement clearly explaining that the customer must obtain a new local provider by the date of service termination in order to continue to make local calls, including 911 calls;

(v) A toll-free number that can be reached by customers for any questions concerning the service termination; and

(vi) A statement explaining that the CLP will no longer make changes to or reconnect any existing service, or accept any orders for new service.

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(i) If the Commission determines that good cause for the proposed termination exists, it may authorize the termination, subject, however, to the provision that the CLP shall have first given adequate notice to its end users.

(j) If the CLP has not given adequate notice to its customers as required by subsection (h) above, or is unwilling to do so, then the underlying carrier shall provide at least fourteen (14) days' notice of the proposed termination to the CLP's customers either by U.S. Mail, recorded announcement, or direct contact. If direct contact is employed, the underlying carrier is required to make at least three (3) attempts over a period of not less than two (2) days to contact each of the CLP's customers. The CLP shall reimburse the underlying carrier for the cost of notifying the CLP's customers of the disconnection of service.

(k) The Commission may extend the fourteen (14) day and forty-five (45) day notice periods provided herein for good cause.

(l) The CLP shall return all deposits to customers and apply all appropriate credits associated with the discontinued service within thirty (30) days of the discontinuation.

DOCKET NO. P-100, SUB 162

COMMISSIONER JAMES Y. KERR, II, dissenting in part:

I must respectfully dissent from that part of the Majority's Order requiring the underlying carrier—usually, the incumbent local exchange carrier (ILEC)—to provide notice to the competing local provider's (CLP's) customers that, if the CLP is unable or unwilling to provide such notice, the CLP's service is being terminated, and the customer's service is in jeopardy. While I share the Majority's belief that adequate notice to end-users is important in this context, the burden of ensuring adequate notice should not be shifted to the underlying carrier, or wholesale provider, regardless of the convenience of doing so. The result achieved by the Majority is characterized by competitive advantage to the ILEC's retail business, confusion in the retail market place, and an actual uncompensated burden on the ILEC's wholesale operations.

I believe that the responsibility for end-user notification in this context should rest with either the Commission or the Public Staff. I concur with the LEC Group's view that such an arrangement is desirable to remove any hint that ILEC's are being given a competitive advantage by making such contacts. Rather, it is more appropriate that a public body, such as the Commission or Public Staff, should make such contacts. The concern that end-users should have adequate notice is one grounded in public interest and safety, and it is not one appropriately imposed upon the wholesale provider, especially absent adequate compensation. It is notable that two neighboring states—Tennessee and South Carolina—have both decided, when addressing similar circumstances, to put such responsibility on the public service commissions. There is a new competitive arena now in telecommunications, and we should reject the mindset demonstrated by the Majority that automatically reaches back to continuing obligations that are more appropriate for a bygone era.

I also do not believe that the practical difficulties cited by the Majority to justify protecting the Commission or Public Staff from this responsibility are insuperable. There have been relatively few of these cases, and the number of end-users affected has been correspondingly small. While it may be necessary to involve the ILECs in the provision of information to the Commission or Public Staff in order for them to make the notifications, if the CLP is unable or unwilling to do so, the ILEC is nevertheless removed from direct contact with the end-user; and no competitive advantage to the ILEC, express or implied, or confusion of end-users is possible.

Lastly, while the Majority has recognized that the ultimate notification requirement places a financial burden on the ILEC that would be difficult to recoup from the CLP, its solution is to note with approval that the ILECs may negotiate provisions in interconnection agreements with CLPs providing for reasonable deposit requirements. This is hardly an immediate or adequate solution, and it will take a long time to implement in any comprehensive way. The LEC Group has suggested a bond approach, which while imperfect, at least would have the virtue of greater immediacy and scope than the solution of the Majority. I would observe that if the Commission or Public Staff were to shoulder the ultimate responsibility for notification, there would be no need for either method because the ILECs would no longer be required to bear a burden for which all agree they should be compensated.

The fact that the actual burden ultimately placed on the ILECs by the Majority might turn out to be small in no way justifies confusing the actual, and appropriate roles, of the parties in this matter. While expedient, perhaps, such actions as the Majority has taken here perpetuate the economic and policy distortions that continue to hamper this industry.

\s\ James Y. Kerr, II
Commissioner James Y. Kerr, II

DOCKET NO. P-100, SUB 162

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking on Discontinuation and/or Reduction of Telecommunications Services	))	ERRATA ORDER

BY THE CHAIR: On August 30, 2006, the Commission issued an Order Promulgating Disconnection Rules in this docket. In that Order, Rule R21-4(k) provides as follows: "(k) The Commission may extend the fourteen (14) day and forty-five (45) day notice periods provided herein for good cause." However, in order to be consistent with Rule R21-4(e), R21-4(k) should read: "(k) The Commission may extend the fourteen (14) day and thirty (30) day notice periods provided herein for good cause."

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb083106.01

DOCKET NO. P-100, SUB 163

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Level 3 Communications, LLC to Amend Commission Rule R17 to Exempt Competing Local Providers from G.S. 62-111(a)	) ORDER) AMENDING) RULE R17

BY THE COMMISSION: On May 5, 2006, Level 3 Communications, Inc. (Level 3) filed a Petition to Amend the Commission's Rules to Streamline Procedures with Respect to Transfers of Control of Non-Dominant Competing Local Providers (Petition). In essence, the Petition requests that the Commission amend Rule R17 to exempt non-dominant competing local providers (CLPs) from the pre-approval requirements of G.S. 62-111(a) and to implement a notice procedure applicable to non-dominant CLPs holding certificates of public convenience and necessity. A copy of the specific rule language proposed by Level 3 to amend Rule R17 is attached to Level 3's Petition.

On May 19, 2006, the Commission issued an Order Seeking Comments from interested parties on the rule amendment proposed in the Level 3 Petition. Said Order made all CLPs and incumbent local exchange companies (ILECs) parties to this proceeding and provided for initial as well as reply comments.

On June 8, 2006, BellSouth Telecommunications, Inc. (BellSouth) filed initial comments. Also, Time Warner Telecom of North Carolina, L.P. (TWT) and US LEC of North Carolina, Inc. (US LEC) jointly filed their initial comments.

On June 22, 2006, reply comments were filed by Level 3 and the Public Staff. On June 23, 2006, TWT and US LEC jointly filed their reply comments.

PETITION OF LEVEL 3

In its Petition, Level 3 notes that G.S. 62-111(a) requires public utilities, which includes CLPs, to file an application and obtain written Commission approval prior to completing a transfer of control transaction. The normal procedure employed by the Commission to process such applications filed by CLPs includes a review of the application by the Commission's staff, placing the matter on an agenda for consideration by the Commission at a weekly Staff Conference and, within a few days following the Staff Conference, the Commission issues a written order ruling on the Application. This process typically encompasses three to eight week.

Level 3 points out that G.S. 62-111(a) was established when a single local exchange carrier was the exclusive provider of service in its designated franchise territory. In that market structure, extensive government regulation of the dominant carrier was necessary to protect captive ratepayers who consumed services provided by a monopoly. Level 3 argues that local competition has dramatically changed the telecommunications market and now consumers can choose freely among non-dominant carriers offering competitive services. Today, non-dominant CLPs are motivated by robust competition for customers and need to complete corporate acquisition and financing transactions quickly, and often, in just a few weeks time. However, non-dominant CLPs remain constrained by the legacy pre-approval requirement of G.S. 62-111(a) and thus cannot react quickly to meet their business needs. Yet, BellSouth and other ILECs that operate under a Commission-approved price regulation plan are exempt from the requirements of G.S. 62-111(a), under the provisions of G.S. 62-133.5(g), and are able to quickly adapt to today's competitive market environment.

Level 3 contends that the pre-approval requirement and process of G.S. 62-111(a) is especially problematic for transactions involving multiple jurisdictions. In some cases, federal agencies and other states with streamlined procedures could have already approved a transaction, but CLPs must await the completion of the Commission approval process to consummate a proposed transaction. This could be the case even when a CLP has only limited or *de minimis* operations or even no customers in North Carolina.

According to Level 3, most carriers operating in multiple jurisdictions also hold authority from the Federal Communications Commission (FCC) to operate as interstate common carriers. Under federal rules, such interstate carriers are required to obtain prior approval to transfer control. However, the FCC has amended its rules to adopt streamlined approval procedures applicable to transfer transactions for a vast majority of non-dominant competitive interstate carriers. Specifically, FCC rules now provide that applications for approval subject to the streamlined treatment are granted within 31 days of publication of the filing, unless the FCC notifies an applicant that its application is being removed from the streamlined processing. Further, in the case of a pro forma transaction, a carrier is only required to file a notice with the FCC within 30 days after control is transferred.

Level 3 adds that very few transfer of control applications filed with the Commission have been contested.

Therefore, Level 3 proposes that the Commission streamline its administrative process for transfers of control transactions by amending Rule R17 to exempt non-dominant CLPs holding certificates of public convenience and necessity from the pre-approval requirements of G.S. 62-111(a) and to implement a notice procedure applicable to such CLPs.

Level 3 explains that its proposed rule implements a streamlined notice procedure in the following manner:

1. Parties to a transfer involving a non-dominant CLP, holding a certificate, would file a notice of the transaction with the Commission ("Notice").

2. The Notice would contain certain basic information about the certified, non-dominant CLP, its operations and the transaction at issue.

3. The Commission would retain jurisdiction over the certified, non-dominant CLP post-closing to make inquiries of the parties, and, if necessary, to take action to protect consumer interests, commence proceedings, and/or impose conditions on the CLPs certificate(s), including reporting requirements.

4. Parties to a *pro forma* transaction involving a non-dominant CLP, holding a certificate, would file a notice with the Commission, post-transaction.

Level 3 believes that Commission has ample statutory authority to amend Rule R17 as it proposes and notes that G.S. 62-110(f1) authorizes the Commission to promulgate rules to regulate CLPs. Level 3 states that the Commission already chose to exempt CLPs from many of the requirements of Chapter 62 when establishing Rule R17 (and the regulatory framework for CLPs) in its Order dated February 23, 1996 in Docket No. P-100, Sub 133. In so doing, the Commission cited its authority under G.S. 62-2 and G.S. 62-110(f1).

Finally, Level 3 represents that the Public Staff supports an exemption and notice procedure as set forth in the Level 3's proposed amendments to Rule R17.

INITIAL COMMENTS

<u>BellSouth</u>:

BellSouth states that it is generally not opposed to the process suggested by Level 3, but recommends that the Commission revise Level 3's proposed rule 1) to ensure that ILECs with whom a CLP has an interconnection agreement (ICA) receive a copy of the notice filed by a CLP with the Commission, and 2) to ensure that the Commission has the authority to potentially interrupt the notice process before the expiration of the 31 days to protect not only consumer interests, but also the interests of ILECs that provide services to CLPs under Commission-approved ICAs.

More specifically, with respect to its first concern that ILECs receive a copy of the notice, BellSouth recommends that Level 3's proposed Rule R17-8(b) be revised as shown below:

> A non-dominant CLP holding a Certificate shall file a Notice with the Commission immediately upon filing an application for a domestic Section 214 License Transfer with the FCC pursuant to 47 C.F.R. § 63.03. <u>Coincident with the filing with the NCUC, the non-dominant CLP shall serve a copy of such Notice on any ILEC in North Carolina with which the CLP has entered into an interconnection agreement approved by this Commission.</u>

BellSouth recommends that CLPs be required to serve the notice on ILECs with which the CLP has an ICA in order to enable the ILEC to contact the CLP to discuss if, or how, the transfer of control will impact the CLP's business relationship with the ILEC. For example, if an ILEC is concerned that a transfer of control may impact its ability to collect money owned by a CLP for services rendered under their ICA, the ILEC's receipt of the notice will allow it the necessary time to 1) discuss the indebtedness with the CLP and, 2) if necessary, ask the Commission to withhold approval until the dispute is resolved, with or without direct action by the Commission.

With respect to its second concern that the Commission should have the authority to potentially interrupt the notice process before the expiration of the 31 days to protect consumer and ILEC interests, BellSouth also recommends that Level 3's proposed Rule R17-8(c) and (d) be revised as shown below:

> Proposed Rule R17-8(c):
>
> Notwithstanding the provision of subsection (b), <u>and notwithstanding the ultimate disposition of the Non-dominant CLP's Section 214 License Transfer proceeding at the FCC</u>, the Commission retains authority to make inquiries,

initiate proceedings, and impose conditions on a Non-dominant CLP's Certificate(s) including reporting requirements, to protect consumer interests <u>and those of any ILEC operating in North Carolina with which the CLP has entered into an ICA approved by this Commission</u>.

Proposed Rule R17-8(d):

~~Not withstanding the close of a Section 214 License Transfer, any proceeding or investigation initiated by the Commission pursuant to subsection (c) shall continue in the Commission's discretion, and the Commission shall retain authority to impose conditions on a CLP's Certificate(s) if necessary to protect consumer interests.~~ If prior to the expiration of the 31-day notice period associated with the Section 214 License Transfer, the Commission determines that the interests of consumers or ILECs will be protected by a proceeding, investigation, or imposition of conditions as described in subsection (c), the Commission may impose whatever conditions it deems necessary. Those conditions will be imposed upon the new entity.

BellSouth asserts that these changes are necessary to eliminate the possibility that a CLP can simply start a 31-day notice clock that the Commission cannot stop and to ensure that the Commission has the authority to protect the interests of ILECs and consumers in connection with a potential transfer of control. BellSouth adds than even the FCC's streamlined process outlined in 47 C.F.R. § 63.03 allows that agency to remove a carrier's application from the streamlined process in the event that timely comments filed by third parties raise public interest concerns that require further review. BellSouth believes its recommended revisions to subsections (c) and (d) would provide the Commission with the same "safety valve" in the event the Commission needs to address concerns raised by third parties after receipt of the CLP's notice filing.

In summary, BellSouth agrees with Level 3's assessment that, historically, the overwhelming number of CLP transfer of control requests have been routine and uncontested, and that a streamlined process is needed to help CLPs react to changing market demands. However, BellSouth recommends that its proposed revisions are needed to give the Commission authority to impose conditions upon the new entity to protect the interests of either consumers or ILECs.

<u>TWT/US LEC</u>:

TWT/US LEC state in their initial comments that they support the Petition of Level 3 for several reasons. First, they contend that the Commission declined to exercise jurisdiction to review the merger of BellSouth with AT&T, yet CLPs are currently required to seek prior approval of all mergers and transfers of control. They argue that CLPs typically do not have a carrier of last resort obligation and CLPs do not have an existing base of captive consumers from which to subsidize competitive efforts. CLPs must also negotiate prices with customers and are subject to a customer's right to choose a different service provider. Therefore, in their opinion, mergers and transfers of control involving CLPs do not raise the level of public concern as with mergers involving ILECs. Second, TWT/US LEC state that the quickly changing telecommunications market requires non-dominant CLPs to maintain flexibility in their operations. Yet, they are unable to complete business combinations on the best timetable to complete and deliver services because of the time it takes to obtain Commission approval of even pro forma transfers. Third, they believe that requiring Commission approval of a transfer of non-dominant CLP ownership or control is inconsistent with public policy in favor of fostering telecommunications competition. They note that ILECs operating under a price plan are not subject to such Commission oversight, which they contend allows ILECs to effectuate transfers quickly, while CLPs must wait for Commission approval. In their opinion, this incongruent and disproportionate treatment is not only ironic but also unsound, given public policy favoring competition. Fourth, TWT/US LEC state that Level 3's proposed amendments to Rule R17 do not contemplate complete disassociation of the Commission from transfers of ownership or control of non-dominant CLPs. Rather, the proposed amendments provide for notice to the Commission and continued jurisdiction to investigate such transfers as needed to protect the public interest. Finally, TWT/US LEC assert that G.S. 62-2(b), in particular, gives the Commission legal authority to amend Rule R17 as requested. In addition, G.S. 62-30 and 62-31 grant the Commission broad power to regulate public utilities and to make and enforce rules and regulations and the Commission has previously cited G.S. 62-2 and 62-160 in exercising its authority to exempt CLPs from other statutory requirements.

REPLY COMMENTS

LEVEL 3:

In its reply comments, Level 3 stated that it is generally not opposed to the revised language proposed by BellSouth for Rule R17-8(b), 8(c), and 8(d). However, Level 3's proposed amendment to Rule R17 does not contemplate implementing a procedure similar to that employed by the FCC, as suggested by BellSouth. Rather, Level 3 has requested that the Commission amend Rule R17 to exempt non-dominant CLPs holding Certificates from the provisions of G.S. 62-111(a) requiring pre-approval of transfer of control transactions and implementing a notice procedure. Level 3's proposed rule also contemplates the Commission taking action to protect consumer interest by making inquiries, commencing proceedings and imposing conditions on a post-closing basis.

Level 3 reiterates that the notice process in its Petition is designed to combat the problematic transfer of control approval process that is a barrier to robust market competition. Level 3 believes the goal is fairness and efficiency for CLPs, ILECs, the Commission and the public by placing CLPs on the same procedural footing as BellSouth.

TWT/US LEC:

In their reply comments, TWT/US LEC state that no party filing initial comments opposed Level 3's Petition, nor did any contend that the Commission is without authority to grant the relief requested in the Petition. Noting the amendments advocated by BellSouth to the rules proposed by Level 3, TWT/US LEC also state that they are opposed to BellSouth's amendments.

As to BellSouth's first proposal regarding notice to ILECs, TWT/US LEC argue that the extent to which a transfer of control may impact the legal relationship between a CLP and an ILEC is governed by the terms of any applicable ICA. For example, the parties to an ICA may have agreed that no notice is required of transfers of control, they may have agreed that no transfer is permitted without the prior written consent of the other party, or they may have agreed to other terms or procedures applicable to transfers. In any event, TWT/US LEC state that the responsibilities of the respective parties are a matter of contract between the parties. TWT/US LEC believe that the filing of a notice as proposed by Level 3 will not impact the ILECs' rights under their ICAs and such filings can be monitored via the Commission's website or inspection of public records.

As to BellSouth's second proposal regarding interruption of a 31-day notice process, TWT/US LEC state that they do not read Level 3's Petition as seeking such a process. TWT/US LEC believe such a process is indeed contrary to the intent of the Petition which is to streamline the transfer process for CLPs as it is for price plan regulated ILECs. TWT/US LEC further argue that, under Level 3's proposed rule, ILECs would remain free to initiate any proceeding necessary to enforce their rights under ICAs. Likewise, the Commission would retain its authority to initiate proceedings should it have concerns with regard to a CLP which arise in connection with a transfer of control.

In summary, TWT/US LEC state that BellSouth's proposed revisions to Level 3's proposed rules are not necessary and serve only to complicate what is otherwise a straightforward and well-justified proposal.

PUBLIC STAFF:

The Public Staff states that it does not object to the change advocated by BellSouth to Level 3's proposed Rule R17-8(b), which essentially requires the non-dominant CLP to serve a copy of the transfer of control notice on ILECs with which the CLP has entered into a Commission-approved ICA. According to the Public Staff, requiring the service of the notice on such ILECs appears to be a reasonable way to allow an ILEC time to contact a CLP that owes it a large amount of money, as BellSouth contends.

However, the Public Staff objects to the changes advocated by BellSouth to Level 3's proposed Rule R17-8(c) and (d). The Public Staff argues that such changes appear to be designed solely to provide ILECs with additional leverage to collect amounts owed by CLPs by preserving the disparity between price plan regulated ILECs and CLPs with respect to the applicability of G.S. 62-111(a). Further, the Public Staff believes those changes are both unnecessary to protect users of CLP services and contrary to the exemption from the pre-approval requirements of G.S. 62-111(a) which the proposed rules are intended to accomplish. Finally, the Public Staff states that the Commission's existing rules regarding reductions and discontinuance of service, the rules emerging from the rulemaking in Docket No. P-100, Sub 162, the FCCs' slamming rules, as well as the proposed rule as written are sufficient to protect users of CLP services that might be affected by a transfer of control.

CONCLUSIONS

Upon careful consideration of the Petition and comments, the Commission finds and concludes that the services or business of CLPs are sufficiently competitive at this time to the extent that it is in public interest to adopt Level 3's proposed amendment to Rule R17, with certain exceptions and/or clarifications as discussed below, pursuant to the authority vested in the Commission under G.S. 62-2(b) and 110 (f1).

First, the Commission notes that Level 3's proposed Rule R17-1(j) defines the term "Non-dominant CLP," and that term later appears in proposed Rule R17-8(a), (b), (c), (e) and (f). There is no discussion or explanation in the record offered by any party as to why the term "Non-dominant CLP", as opposed to simply "CLP", is advisable or necessary to include in a rule. Therefore, the Commission concludes that Level 3's proposed Rule 17-1(j) should be eliminated, the subsections should be renumbered, and that the term "Non-dominant" should be eliminated from Level 3's proposed Rule R17-8(a), (b), (c), (e) and (f).

Second, the Commission further concludes that Level 3's proposed Rule R17-8(f) should be amended as shown below:

> Nothing in the rule shall be deemed to exempt an entity ~~other than a non-dominant CLP holding a Certificate~~ from the requirements of Rule R17-2.

The purpose of this amendment is to make it clear that no entity can provide local exchange service without first complying with the requirements of Rule R17-2, even when an entity without a Certificate is acquiring the assets and customers of a CLP certificate holder.

Finally, the Commission concludes that BellSouth's recommended amendment to Level 3's proposed Rule R17-8(b) should be adopted, but BellSouth's recommended amendments to Rule R17-8(c) and (d) should be rejected for the reasons stated by the Public Staff.

A copy of the rule consistent with the Commission findings and conclusions is attached hereto as Appendix A.

IT IS THEREFORE, ORDERED that Commission Rule R17 shall be amended as set forth in Appendix A attached to this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

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Rule R17-1. Definitions

(f) FCC -- The Federal Communications Commission.

(j) Notice -- A document filed with the Commission pursuant to Rule R17-8 which includes the following: (1) The name, address of the principal headquarters, and telephone and facsimile numbers for each of the parties to the Section 214 License Transfer or *Pro forma* Transaction and any changes in the Name and Contacts information provided in the non-dominant CLP's original Competing Local Provider Application; (2) A statement setting forth a description of the Section 214 License Transfer or *Pro forma* Transaction; (3) A copy of the application for a domestic Section 214 License Transfer, or in the case of a *Pro forma* Transaction the notification letter, filed with the FCC; and (4) A copy of the FCC's Public Notice of the Section 214 License Transfer or *Pro forma* Transaction.

(m) *Pro forma* Transaction – Any corporate restructuring, reorganization or liquidation of internal business operations that does not result in a change in ultimate ownership or control of the carrier's lines or authorization to operate.

(n) Section 214 License Transfer – A transfer of control of lines or authorization to operate pursuant to section 214 of the Communications Act of 1934 subject to the streamlining procedures for domestic transfer of control applications in 47 C.F.R. § 63.03.

(p) USDOJ – The United States Department of Justice.

Rule R17-8. Procedures for Transfers of Control

(a) A CLP holding a Certificate is exempt from the provisions of G.S. § 62-111(a) requiring approval of transfers of control transactions, except as set forth in this rule.

(b) A CLP holding a Certificate shall file a Notice with the Commission immediately upon filing an application for a domestic Section 214 License Transfer with the FCC pursuant to 47 C.F.R. § 63.03. Coincident with the filing with the NCUC, the CLP shall serve a copy of such Notice on any ILEC in North Carolina with which the CLP has entered into an interconnection agreement approved by this Commission.

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(c) Notwithstanding the provision of subsection (b), the Commission retains authority to make inquiries, initiate proceedings and impose conditions on a CLP's Certificate(s) including reporting requirements, to protect consumer interests.

(d) Notwithstanding the close of a Section 214 License Transfer, any proceeding or investigation initiated by the Commission pursuant to subsection (c) shall continue in the Commission's discretion, and the Commission shall retain the authority to impose conditions on a CLP's Certificate(s) if necessary to protect consumer interests.

(e) A CLP holding a Certificate shall file a Notice with the Commission no later than 30 days after control of the carrier is transferred pursuant to a *Pro forma* Transaction.

(f) Nothing in this rule shall be deemed to exempt an entity from the requirements of Rule R17-2.

DOCKET NO. E-2, SUB 889

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 Pursuant to G.S. 62-133.2 and NCUC Rule R8-55	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Wednesday, August 9, 2006 at 10:00 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Jo Anne Sanford, Presiding; and Commissioners Robert V. Owens, Jr.; Sam J. Ervin, IV; Lorinzo L. Joyner; James Y. Kerr, II; and Howard N. Lee

APPEARANCES:

For the Applicant:

Len S. Anthony, Deputy General Counsel – Regulatory Affairs, and Kendal C. Bowman, Associate General Counsel, Progress Energy Service Company, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Public Staff:

Antoinette R. Wike, Chief Counsel, and William E. Grantmyre, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the Attorney General:

Len G. 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. (CUCA):

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

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

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

BY THE COMMISSION: Pursuant to G.S. 62-133.2 and Commission Rule R8-55(e), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (PEC or Company) is required to file, at least 60 days prior to the first Tuesday in August of each year, an Application for a change in rates based solely on changes in the cost of fuel and the fuel component of purchased power. On June 2, 2006, PEC filed its Application along with the testimony and exhibits of Company witnesses Dewey S. Roberts and Bruce P. Barkley. In its Application, the Company requested an increment of 1.090 ¢/kWh (1.126 ¢/kWh including gross receipts tax) to the base factor of 1.276 ¢/kWh approved in PEC's last general rate case, Docket No. E-2, Sub 537, resulting in a recommended fuel factor of 2.366 ¢/kWh. The Company also requested an increment of 0.491 ¢/kWh (0.507 ¢/kWh including gross receipts tax) for the Experience Modification Factor (EMF) to collect $178.4 million of under-recovered fuel expense. The Company proposed that the EMF rider be in effect for a fixed 12-month period.

On June 7, 2006, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which the Commission granted on June 8, 2006.

On June 7, 2006, the Attorney General filed a notice of intervention, pursuant to G.S. 62-20.

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

On June 8, 2006, the Commission issued its Order Scheduling Hearing Dates, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice. The Commission scheduled the hearing for August 9, 2006 and required that intervenor testimony and exhibits, as well as petitions to intervene, be filed by July 25, 2006.

On June 26, 2006, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed a petition to intervene, which the Commission granted on July 24, 2006.

On July 25, 2006, the Public Staff filed the direct testimony of Randy T. Edwards, the affidavit of Thomas S. Lam and a Settlement Agreement entered into by PEC, CIGFUR II and the Public Staff. This agreement set forth those parties' proposed resolution of issues, including the total fuel factors to be effective for the next three fuel cases, so as to phase in the rate increase PEC originally requested in this proceeding.

On August 4, 2006, PEC filed affidavits of publication showing that public notice had been given as required by Rule R8-55(f) and the Commission's June 8, 2006 Order.

The docket came on for hearing, as ordered, on August 9, 2006. Herman Jaffe appeared as a public witness. PEC then presented witnesses Dewey S. Roberts and Bruce P. Barkley for cross-examination. Following their testimony and cross-examination, the Public Staff presented Randy T. Edwards and Thomas S. Lam for cross-examination. No other parties presented a witness. The Commission, by Order issued August 11, 2006, requested the filing of proposed orders or briefs by September 1, 2006 and reply briefs by September 8, 2006. In such Order, the Commission also requested that the parties address eight questions or issues regarding the Settlement Agreement.

On September 1, 2006, PEC filed a Revised Alternate Settlement Agreement entered into by PEC, CIGFUR II and the Public Staff. A copy of the Revised Alternate Settlement Agreement is attached hereto as Appendix A. On that same date, PEC and Public Staff jointly filed a proposed order and briefs were filed by the Attorney General, CIGFUR II and CUCA.

On September 8, 2006, PEC filed a reply brief and the Public Staff filed a letter of support of the PEC reply brief. CUCA filed a reply brief on September 11, 2006.

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 now makes the following:

FINDINGS OF FACT

1. Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. PEC is engaged in the business of generating, transmitting, and selling electric power to the public in North Carolina. 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, 2006.

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

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

5. PEC is entitled to a fuel factor equal to 2.366¢/kWh (2.444¢/kWh including gross receipts tax) pursuant to provisions of G.S. 62-133.2.

6. It is reasonable to apply a 50% fuel ratio to the energy cost of purchases from power marketers and other sellers that are unable or unwilling to provide PEC with actual fuel costs.

7. The test period North Carolina retail fuel expense under-recovery in this proceeding is $165,239,556.

8. It is appropriate to reduce the fuel expense under-recovery for purposes of this proceeding by $1,541,923 to reflect the final settlement of PEC's freight rate dispute with Norfolk Southern Railroad.

9. PEC should be allowed to recover $3,462,000 of the $55.46 million under-recovery deferred from Docket No. E-2, Sub 784, plus interest of $10,820,667, both of which are eligible for recovery in this case per the Stipulation agreed to by the Parties and approved by the Commission in Docket No. E-2, Sub 784.

10. The appropriate EMF increment to use in this proceeding is 0.490 ¢/kWh (0.506 ¢/kWh including gross receipts tax) based on a total fuel expense under-recovery of $177,980,300.

11. The Revised Alternate Settlement Agreement entered into by PEC, the Public Staff, and CIGFUR II is just and reasonable, in the public interest, and should be approved, as it phases-in the rate increase PEC is otherwise entitled to based upon the record in this proceeding and the provisions of G.S. 62-133.2.

12. The prudently-incurred direct, incremental, transaction-related costs of financial and physical hedging activities utilized by PEC to reduce the volatility of its natural gas costs and charged or credited to FERC Account No. 547 should be treated as recoverable fuel costs pursuant to G.S. 62-133.2, subject to the same standards of reasonableness and prudence as other fuel costs incurred by the Company.

13. The Commission accepts the increase in the Maximum Dependable Capacity of Brunswick Unit No. 2 to 937 MWs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2 sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for a historical 12-month period. In Commission Rule R8-55(b), the Commission prescribed the twelve months ending March 31 as the test period for PEC. All pre-filed exhibits and direct testimony submitted by the Company in support of its Application utilized the twelve months ended March 31, 2006, as the test year for purposes of this proceeding. The Company made the standard adjustments to the test period data to reflect normalizations for weather, customer growth, generation mix, and Southeastern Power Administration (SEPA) and North Carolina Eastern Municipal Power Agency (NCEMPA) transactions.

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, 2006.

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

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

Commission Rule R8-52(b) requires each utility to file a Fuel Procurement Practices Report at least once every ten years, as well as each time the utility's fuel procurement practices change. In its Application, the Company indicated that the procedures relevant to the Company's fuel procurement were contained in the Fuel Procurement Practices Report, which was updated in June 2005. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a). These reports were filed in Docket No. E-2, Sub 862 for calendar year 2005 and in Docket No. E-2, Sub 888 for calendar year 2006.

Company witness Barkley described in detail the Company's coal and gas procurement practices. The Company relies on short-term and long-term simulation models to estimate the coal and gas requirements at PEC 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 Company's coal requirements. Coal contracts are awarded based on economic evaluation, supplier credit review, past performance and coal specifications. Gas contracts follow a similar process.

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. PEC makes fuel purchases at the best prices possible giving due regard to reliability of supply needs and environmental compliance. Witness Barkley concluded that PEC prudently operated its generation resources and purchased power during the period under review in order to minimize its costs.

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

Regarding the operation of PEC's natural gas and coal fired plants, witness Roberts explained that PEC's combustion turbines averaged a 94.23% equivalent availability and a 3.60% capacity factor for the twelve-month period ending March 31, 2006. According to his testimony, these performance indicators are consistent with combustion turbine generation's intended purpose. This generation was almost always available for use, but operated minimally. PEC's intermediate Richmond County combined cycle unit had a 93.04% equivalent availability and a 23.90% capacity factor for the twelve-month period ending March 31, 2006. The Company's intermediate coal fired units had an average equivalent availability of 90.85% and a capacity factor of 64.07% for the twelve-month period ending March 31, 2006. Witness Roberts testified that these performance indicators for the intermediate units are indicative of good performance and management. Witness Roberts also testified that PEC's fossil base load units had an average equivalent availability of 90.86% and a capacity factor of 70.16% for the twelve-month period ending March 31, 2006. Thus, he concluded that the fossil base load units were also well managed and operated.

With regard to the operation of PEC's nuclear generation facilities, witness Roberts explained that, for the twelve-month period ending March 31, 2006, the Company's nuclear generation system achieved a net capacity factor of 93.75%. This capacity factor included nuclear plant refueling outages. He, further testified that, during the period April 1, 2005, through March 31, 2006, the Company's Boiling Water Reactor (BWR) nuclear generation achieved a net capacity factor of 90.77%. In contrast, the North American Electric Reliability Council (NERC) five-year average capacity factor for 2000-2004 for similar size BWR commercial nuclear generation in North America was 90.35%. The Company's Pressurized Water Reactor (PWR) nuclear generation achieved a net capacity factor of 97.17%. In contrast, the NERC five-year average capacity factor for 2000-2004 for similar size PWR commercial nuclear generation in North America was 86.63%. The Company's nuclear system incurred a 1.88% forced outage rate during the twelve-month period ending March 31, 2006 compared to the industry average of 4.76% 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 systemwide nuclear capacity factor, based upon a two-year simple average of the systemwide 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 the Company's test year average capacity factor calculation.

Regarding power purchases to displace Company owned generation, witness Roberts testified that the Company 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 the Company. 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 witness Lam testified that he reviewed the Company's test period fuel prices and determined they were reasonable. Public Staff witness Edwards testified that he reviewed the Company's Monthly Fuel Reports and Company's fossil, nuclear and purchased power fuel costs. His only adjustment to PEC's test period expenses was a reduction of $441,311, which PEC did not oppose. No party offered any testimony contesting the Company's test period fuel procurement or power purchases.

No other party offered any evidence regarding PEC's fuel procurement or power purchases, or base load power plant performance during the test period. Thus, the Commission finds and concludes that PEC's fuel procurement procedures and power purchasing practices and the operation of the Company's base load plants were reasonable and prudent during the test period.

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

The evidence supporting these findings can be found in the testimony and exhibits of Company witnesses Barkley and Roberts and the testimony of Public Staff witnesses Edwards and Lam.

In Barkley Exhibit No. 5, the Company calculated a fuel factor of 2.237 ¢/kWh based on normalized capacity factors for its nuclear units in accordance with Commission Rule R8-55(c)(1), by using the five-year NERC Equipment Availability Report 2000-2004 average for BWRs and PWRs. The workpapers included in Barkley Exhibit No. 9 show kWh normalization for customer growth and weather at both meter and generation levels performed in a manner consistent with past cases. Normalization adjustments were also made for SEPA deliveries and hydro generation. The unit prices used for coal, nuclear, internal combustion turbines, purchases and sales were also calculated in a manner consistent with past cases. The NERC five-year capacity factors for Brunswick Unit Nos. 1 and 2, both BWRs, were normalized at 86.61%, and the capacity factors of the Robinson and Harris Units, both PWRs, were normalized at 88.76%. The Company's NERC normalized calculations resulted in a system nuclear capacity factor of 87.61% using this data.

Witness Barkley did not recommended a factor of 2.237 ¢/kWh; rather, he recommended the establishment of a fuel factor of 2.366 ¢/kWh based on forecasted nuclear generation performance, kWh sales and fuel costs. The derivation of this recommended factor is shown in Barkley Exhibit No. 5A. He explained that PEC's forecast of fuel costs for the period the rate will be in effect indicates significant increases for both natural gas and coal. Witness Barkley testified that none of the market forces that caused the increase in coal prices indicated on Barkley Exhibit No. 1 are likely to change. These include production costs for coal mining, heavy demand for coal both domestically and internationally, environmental requirements and the fact that coal remains much less expensive than natural gas. Consequently, as current below- market contracts expire and are replaced with new contracts, they will include higher prices. Based on these factors, the Company's fuel costs are projected to be higher in the October 2006 though September 2007 time period than experienced during the period of April 2005 through March 2006. Further, PEC anticipates increases in the price of rail transportation due to fuel surcharges passed along by rail providers. These surcharges are based on the price of crude oil, which has reached record high levels recently. The total delivered cost of coal is expected to increase from $67.56 per ton during the review period up to $73.95 per ton for the year ending September 30, 2007.

With regard to natural gas prices, witness Barkley explained that extremely high prices were experienced, up to $20/mmbtu, in the wake of Hurricanes Katrina and Rita which occurred during August and September of the test period. PEC expects continued volatility in the gas markets. While gas prices have come down since these extremely high levels, PEC's forecasted cost, excluding transportation, for the year ending September 30, 2007 of $12.14/mmbtu exceeds the $10.14/mmbtu experienced during the test period as natural gas prices for the forecast period remain high in light of the demand for natural gas and record crude oil prices. Recent and projected market prices for natural gas are shown on Barkley Exhibit No. 2. The computation of the 2.366 ¢/kWh fuel factor is summarized below:

Generation Type	MWhs	Fuel Cost
Nuclear	28,879,607	$132,826,254
Purchases – Cogen	670,761	38,408,187
Purchases – AEP Rockport	1,726,358	26,739,695
Purchases – Broad River	365,134	53,207,144
Purchases – SEPA	181,546	0
Purchases – Other	255,945	11,936,141
Hydro	681,219	0
Coal	32,196,912	985,204,712
IC & CC	2,080,070	296,628,836
Sales	(2,574,777)	(118,446,145)

Total Adjusted	$64,462,775	$1,426,504,824
Less NCEMPA:		
PA Nuclear	3,651,701	$18,167,700
PA Buy-Back & Surplus	(439,806)	(2,464,900)
PA Coal	1,305,470	41,597,900
System Projected Fuel Expense		$1,369,204,124
Projected kWh meter sales		57,881,525,000
Projected Fuel Factor (¢/kWh)		2.366

After review of the Company's Application, Public Staff witness Lam concluded that the fuel costs incurred by the Company during the test period were reasonable and prudent and that the Company's forecasted fuel costs were also reasonable. Witness Lam reached this conclusion after reviewing the projected nuclear capacity factors and relevant fuel cost information.

No other party presented any evidence regarding PEC's forecasted fuel costs during the period the rate will be in effect, nor did any other party challenge PEC's forecasted fuel costs or recommended fuel factor. Thus, the Commission finds that PEC is entitled to a fuel factor of 2.366 ¢/kWh (2.444¢/kWh including gross receipts tax) pursuant to the provisions of G.S. 62-133.2. Such a fuel factor would also best match PEC's fuel revenues and costs during the period the rate will be effect.

In the pre-filed direct testimony and exhibits submitted by Company witness Barkley, PEC also requested recovery of $178,421,611 of under-recovered fuel expense consisting of three components. One component is the test period under-recovery of $165,239,556 using the fuel factors approved by the Commission in Docket No. E-2, Subs 851 and 868. This amount includes the use of a 50% fuel to energy cost ratio for certain purchases from marketers, as discussed below. The second component is $3,462,000 of the $55.46 million fuel expense deferred from PEC's 2001 fuel case, Docket No. E-2, Sub 784, plus interest of $10,820,667. The third component is a reduction of $1,100,612 associated with the final settlement of PEC's rate dispute with the Norfolk Southern Railroad. The Company requested an EMF increment of 0.491 ¢/kWh (0.507 ¢/kWh including gross receipts tax) to recover the full $178,421,611 under-recovered amount, which was calculated by dividing the under-recovery by kWh sales of 36,337,162,068.

Public Staff witness Edwards reviewed the Company's calculation of the EMF for the test period and recommended only one adjustment, in the amount of $441,311, based upon the Public Staff's determination that the Norfolk Southern settlement adjustment should have been $1,309,311 rather than $1,100,612. Applying 10% interest to the Public Staff's calculation of the additional $208,699 during the applicable period increased the total adjustment to $441,311. PEC did not object to this adjustment. The Public Staff's adjustment resulted in a total under-recovery of $177,980,300. This adjustment decreased the proposed EMF increment to 0.490 ¢/kWh (0.506 ¢/kWh including gross receipts tax).

Witness Edwards stated that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for determining the fuel cost proxy for purchases from marketers and from other sellers who refuse to provide fuel cost information to the purchasing utility. The Public Staff believes this methodology for determining a proxy fuel cost meets the criteria set forth in the Commission's 1996 Duke Power Company (Duke) fuel case Order. For purposes of calculating a percentage to be applied in fuel proceedings held in 2006, the Public Staff performed a review of the fuel component of off-system sales for Duke, Dominion North Carolina Power, and PEC, for the twelve months ended December 31, 2005. These sales are set forth in the utilities' Monthly Fuel Reports. This analysis is similar to that performed by the Public Staff for the 1997 Stipulation addressing this matter (which was applicable to the 1997 and 1998 fuel proceedings) and the 1999 Stipulation (which was filed by Carolina Power & Light Company 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 fuel proceedings held in 2002, 2003, 2004, and in 2005. The methodology used for each of the above-mentioned Stipulations and subsequent fuel proceedings has been accepted by the Commission as reasonable in each fuel case since the beginning of 1997.

G.S. 62-133.2 requires that purchased power-related costs recovered in fuel adjustment proceedings consist of only the fuel cost component of those purchases. However, in its Order in Duke's 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."

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 proceedings conducted pursuant to G.S. 62-133.2, 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, 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 past Stipulations and in the analysis for this proceeding meets the criteria set forth in the 1996 Duke Order.

As part of its current review, the Public Staff analyzed the off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 45.33% to 57.67%. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel ratio should be 50%. Witness Edwards acknowledged that PEC utilized the 50% ratio for purposes of this proceeding.

The Commission notes that fuel costs from marketer purchases are an important part of the Company's overall fuel cost. The use of a ratio to determine marketer fuel costs evolved with the emergence of an active wholesale bulk power market beginning in 1996, which prompted this Commission to address the issue in the 1996 Duke Power Company fuel case. In its Order in that proceeding, the Commission stated, "When faced with a utility's reliance upon some such form of proof [i.e., a reasonable and reliable proxy] in a future fuel adjustment proceeding, the considerations will be 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." Recognizing that an active wholesale bulk power market continues to evolve and applying this standard to the evidence presented herein, the Commission concludes, as it has in past proceedings, that the methodology recommended and used by the Public Staff to determine the fuel cost component of purchases from power marketers and other suppliers (1) satisfies the requirements set forth in the 1996 Duke fuel case order, and (2) is reasonable and will be accepted for purposes of this proceeding. The Commission approved the use of a 50% ratio in the most recent Duke Power fuel proceeding, Docket No. E-7, Sub 805. The Commission also accepts the use of a 50% ratio in this proceeding as recommended by Public Staff witness Edwards and adopted by PEC.

No other party submitted any evidence in this proceeding regarding PEC's test period under-recovery or calculation of the appropriate EMF. Thus, the Commission concludes that PEC's under-recovery of prudently incurred fuel costs appropriate for recovery in this proceeding is $177,980,300 and that the corresponding EMF to which PEC is entitled is 0.490 ¢/kWh, excluding gross receipts tax.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 11

The evidence supporting this finding can be found in the testimony of PEC witness Barkley and the affidavit and testimony of Public Staff witness Lam.

Public Staff witness Lam testified that the total fuel factor resulting from the Public Staff's analysis to which PEC is entitled is 2.856 ¢/kWh (2.366 ¢/kWh fuel factor plus 0.490 ¢/kWh EMF). He further testified that, by the time the fuel factor approved in this proceeding becomes effective, the under-collection in the Company's deferred account is expected to be in excess of $300,000,000. As a result PEC, CIGFUR II, and the Public Staff entered into a Settlement Agreement that is designed to phase-in the rate increase to which PEC is entitled under G.S. 62-133.2 and moderate the impact of the increase in the fuel factors necessary to recover these increased fuel costs over the next three fuel cases. Under the Settlement Agreement, PEC's total fuel factor, excluding gross receipts tax, will be 2.550 ¢/kWh effective October 1, 2006. PEC will be allowed to charge and collect 6% interest on an amount equal to the under-collection resulting from a total fuel factor of 2.550 ¢/kWh rather than 2.856 ¢/kWh effective October 1, 2006. On October 1, 2007, the total fuel factor will increase to 2.675 ¢/kWh, and on October 1, 2008, the total fuel factor will increase to 2.750 ¢/kWh. The agreed upon total fuel factors are estimated to result in increases of approximately 5.5%, 1.4%, and 0.9%, respectively, for PEC's residential customers for the twelve-months beginning October 1, 2006, October 1, 2007, and October 1, 2008.

Public Staff witness Lam recommended approval of the Settlement Agreement, which includes a total fuel factor of 2.550 ¢/kWh, excluding gross receipts tax, effective October 1, 2006, rather than a total fuel factor of 2.856 ¢/kWh to which PEC would otherwise be entitled pursuant to G.S. 62-133.2(d).[1] With an EMF increment of 0.490 ¢/kWh, this total fuel factor will result in a fuel factor of 2.060 ¢/kWh.

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[1] G.S. 62-133.2(d) provides:

"The Commission shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses 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. . ."

The Revised Alternate Settlement Agreement[1] offers a fair and reasonable method to both phase-in the fuel factor increase PEC is clearly entitled to based upon the record in this proceeding and addresses recovery of the large fuel cost under-recovery that is expected at September 30, 2006[2]. It also significantly mitigates the near-term impact to PEC's customers of the drastically increasing cost of coal and natural gas. Thus, the Commission concludes that it is in the public interest to adopt the Settlement Agreement. In the absence of the phase-in approach set forth in the Settlement Agreement, based upon the record in this proceeding, the Commission would be required by G.S. 62-133.2 to grant PEC a total fuel factor in this case of 2.856 ¢/kWh, exclusive of gross receipts tax. The record contains no evidence to support any other result. The total fuel factors for years 2006, 2007, and 2008 contained in the Settlement Agreement are simply a mechanism to mitigate the impact to PEC's customers of the full rate increase that would otherwise be required in this proceeding by phasing in the rate increase. Nevertheless, the Commission would prefer to follow the usual practice of setting annual fuel adjustment rates one year at a time and will be inclined to look with disfavor on phase-in rate proposals in future fuel adjustment proceedings. The action taken in this case is, however, clearly reasonable and appropriate based on the large fuel cost under-recovery incurred by PEC to date in combination with escalating fuel prices. That said, the Commission concludes that the better practice to follow in future fuel cases is to allow cost recovery on a more current basis; i.e., over the 12-month period covered by the rates set in those cases.

The Commission had concerns about the legality of the provision in the original Settlement Agreement which allowed PEC to file an application for an adjustment to its fuel cost recovery factor and experience modification factor (EMF) upon termination of the agreement. The Revised Alternate Settlement Agreement eliminated that provision. The Settlement Agreement now provides that, upon the termination of such Agreement, PEC shall file an application for an adjustment for its fuel cost recovery factor and EMF pursuant to G.S. 62-133.2 and Commission Rule R8-55. Thus, the Commission's concerns and the legal issue regarding this matter have now been resolved and, for that reason, the Commission will approve the Revised Alternate Settlement Agreement rather than the original version.

The Commission also questioned whether it possesses the necessary legal authority to approve the proposed Real Time Pricing Energy Rider (RTP Energy Rider), which was discussed in the Settlement Agreement, in a fuel adjustment proceeding. The Parties to the Settlement Agreement subsequently advised the Commission that they are not requesting approval of the proposed Rider in this docket. Rather, as explained in the Settlement Agreement, PEC, through a separate filing in Docket No E-2, Sub 893, has requested Commission approval of the proposed RTP Energy Rider. PEC has requested that the new Rider be made effective on the same date as its revised fuel factor, October 1, 2006. PEC has further advised the Commission that, while the RTP Rider, once approved, will continue in effect for the three-year period regardless of whether the Commission approves the fuel adjustment proceeding settlement, the rate decrement itself will be revised each year. Thus, the Commission's legal concerns regarding the Real Time Pricing Energy Rider have been resolved for purposes of this proceeding. The rate rider in question will be considered for approval in Docket No. E-2, Sub 893 and is not part of the Settlement Agreement approved in this proceeding.

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[1] For the remainder of this Order, references to the Settlement Agreement refer to the Revised Alternate Settlement Agreement and not the original Settlement Agreement.

[2] PEC shall provide CIGFUR II and the Public Staff quarterly reports beginning February 1, 2007 comparing the actual fuel cost under-recovery as of the close of the previous calendar quarter to the deferred amounts contained in Attachment 1. Such reports shall also be filed by PEC with the Commission in this docket.

CUCA is the only party which opposed approval of the Settlement Agreement. CUCA maintains that the Commission should reject the Settlement Agreement on grounds that the Commission does not possess the necessary statutory authority to approve such Agreement; that approval of such Agreement would violate the fundamental constitutional protections and due process rights of CUCA and others; and that the record is insufficient to allow the Commission to determine whether the Agreement is just, reasonable, and prudent.

The Commission rejects CUCA's arguments for the following reasons.

In approving the Settlement Agreement, the Commission has found good cause, on the facts of this specific case, to set the total fuel factors that PEC should be allowed to charge for the next three years. This Order will be legally binding upon all Parties upon the expiration of the time for seeking judicial review hereof. This decision has been made, however, with the clear understanding that G.S. 62-80 provides the Commission with the statutory authority to rescind, alter, or amend such decision if the Commission, for instance, finds a material change in PEC's fuel costs during the three-'year period of time covered by the Settlement Agreement. Thus, the Commission may, on its own motion or upon the motion of an entity not a party to the Settlement Agreement, revisit the Commission's Order in this proceeding in the future. In addition, the Settlement Agreement by its terms clearly contemplates that the Commission will conduct annual fuel cost proceedings for PEC in 2007 and 2008 as required by G.S. 62-133.2. The Commission will also conduct a prudence review of PEC's test year fuel costs and purchasing practices in each of those cases as required by law. The Commission can, at that time, review this Order and decide whether the fuel factors set forth in the Settlement Agreement continue to be the appropriate factors in order to provide just and reasonable rates for PEC's customers. To the extent this Order may need to be modified based upon the evidence presented in PEC's 2007 or 2008 fuel adjustment proceedings, the Commission possesses the necessary statutory authority to do so under G.S. 62-80. Nothing in G.S. 62-133.2 explicitly precludes a phase-in of the type deemed appropriate here; the Supreme Court did not comment adversely upon the phase-in approved in Duke's 1985 general rate case in State ex rel. Utilities Commission v. Eddleman, 320 N.C. 344, 358 S.E.2d 339 (1987). The Commission further notes that the Public Staff and the Attorney General, in their capacities as representatives of the using and consuming public, assert that the Commission possesses the necessary statutory authority to approve the Settlement Agreement. The Commission has placed great reliance on the legal opinions expressed by the Public Staff and the Attorney General in deciding this case.

With regard to CUCA's argument that acceptance of the Settlement Agreement is unconstitutional, the Commission finds persuasive the legal principle applied by the North Carolina Supreme Court in the case of State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998). In that case, the issue before the Court was whether a stipulation entered into by less than all of the parties to a proceeding could or should be adopted by the Commission absent substantial evidence supporting the justness and reasonableness of the stipulation. In addressing this issue, the Court held:

> "Thus, we hold that a stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts that the Commission finds relevant to the fair and just determination of the

> proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented. . . ." .

Id. at 466, 500 S.E.2d at 703.

Thus, the Commission may adopt the Settlement Agreement entered into and submitted by PEC, CIGFUR II, and the Public Staff provided the Commission makes its own independent conclusion that the provisions of the Settlement Agreement are just and reasonable and consistent with applicable law based upon substantial evidence of record.

The evidence of record in this proceeding only permits two courses of action. The first is to grant PEC a total fuel factor of 2.856 ¢/kWh. The second course of action permitted based upon the record of this proceeding is approval of the Settlement Agreement that phases-in the rate increase to which PEC is entitled by statute. The evidence of record clearly supports approval of the Settlement Agreement. The Commission has independently determined and concluded that it has the authority to adopt the approach set out in the Settlement Agreement and that it is in the public interest, based upon the record in this case, to phase-in the rate increases necessary to allow PEC to recover its just, reasonable, and prudent fuel expenses rather than impose upon PEC's customers a larger rate increase at this time.

CUCA's assertion that the Commission has not heard or received any competent evidence to support the rates at which the Settlement sets the fuel cost factors for 2008 and 2009 is also incorrect. The attachment to the Settlement Agreement demonstrates that the fuel cost factors proposed for 2006, 2007, and 2008 result in the recovery of PEC's ongoing just and reasonable fuel costs and the deferred fuel cost balance over the three-year period addressed by the Settlement Agreement. No party challenged the validity of the substance and content of this evidence. In addition, Public Staff witness Lam testified that the factors set forth in the Settlement Agreement are designed to moderate the impact of the fuel factors necessary to recover PEC's fuel costs over the next three fuel cases. Thus, the record supports the factors in question. The evidence offered by the witnesses for PEC and the Public Staff, including Attachment 1 to the Settlement Agreement, support findings that the following total fuel factors (exclusive of gross receipts tax and including the EMF) are just and reasonable; that they are based on the best available evidence of PEC's prudently-incurred, ongoing fuel costs during the three-year period covered by the Settlement Agreement; and that they will facilitate recovery, to the maximum extent possible, of PEC's deferred fuel cost balance:

Effective October 1, 2006:	2.55 ¢/kWh
Effective October 1, 2007:	2.675 ¢/kWh
Effective October 1, 2008:	2.75 ¢/kWh

Such total fuel factors are, nevertheless, subject to reconsideration in PEC's 2007 and 2008 fuel adjustment cases pursuant to G.S. 62-80.

Nor has CUCA been deprived of fundamental due process in this proceeding and there is certainly no compelling reason to reopen the hearing. CUCA intervened in this proceeding at an early stage, had the opportunity to conduct discovery, and had every opportunity to cross-examine and in fact did cross-examine the witnesses for PEC and the Public Staff. CUCA was entitled to, but chose not to, present a witness or witnesses, and was allowed to file initial and reply briefs. Clearly, CUCA was given ample notice and the opportunity to be heard in this proceeding and, therefore, its fundamental due process rights were honored and protected. Further, CUCA's rights in future proceedings are not diminished as a result of the Commission's approval of the Settlement Agreement in this proceeding. CUCA's objections and criticisms of the Settlement Agreement have been fairly and adequately considered and addressed in this Order and have been found to lack merit. There has been no denial or abridgement of due process in this case. The Commission further notes that CUCA has an absolute right to attempt to appeal this Order.

Finally, the Commission notes that, while CUCA has advocated that the Commission reject the Settlement Agreement, it has refrained from stating with specificity what it would have the Commission order and require in this case. Intervenors are certainly free to advocate their positions before the Commission in contested cases, but the Commission would prefer that a party which specifically opposes the relief requested (approval of the Settlement Agreement in this case) recommend in its brief or proposed order what action should be taken by the Commission. Simply advocating that the Settlement Agreement should be rejected without stating what the final outcome should be is not particularly helpful to the Commission.

Regarding the clarity of certain provisions of the Settlement Agreement, the Commission has satisfactorily resolved any such issues by asking the parties to address the eight questions contained in the Commission's Order of August 11, 2006. PEC's and the Public Staff's responses to those questions[1], the resultant changes made in the Revised Alternate Settlement Agreement, and the provisions of this Order clearly address, resolve, or eliminate any ambiguity with regard to the intent of the provisions of the Settlement Agreement.

The Commission finds that the Settlement Agreement represents an acceptable proposal which equitably addresses PEC's deferred and projected fuel costs. Importantly, while the Attorney General and CUCA are not signatories to the Agreement, the customers they represent are beneficiaries of the Agreement. Moreover, neither has proposed an alternative to the substantial increase to which PEC is entitled based on the uncontroverted evidence in this case and the Attorney General has strongly argued that the Commission has the legal authority to approve the Settlement Agreement. CUCA's attorney did question witness Barkley about the general concept of a type of seasonal fuel factor to be discussed by PEC and its South Carolina customers and the possibility that fuel costs might be adjusted to reflect line loss differentials among customer classes. However, these questions do not constitute an alternative rate proposal, particularly in the absence of testimony containing specific recommendations supported by competent evidence. At best, such questions suggest only the possibility of a different rate design for recovering the total fuel cost, current and deferred, that PEC has incurred through the end of the test period in a future case. The Attorney General questioned PEC about its policies for purchasing coal under contract and on the spot

[1] The Commission agrees with CUCA's reply comments that there is a contradiction between Section 5 of the Settlement Agreement and the statement in the Joint Proposed Order filed by PEC and the Public Staff that if the Commission finds that any of PEC's incurred fuel costs in 2007 or 2008 were imprudent and therefore should be disallowed, "such disallowance could not be used by any of the parties to the Settlement Agreement to terminate the Agreement unless the disallowance caused PEC's deferred fuel balance to vary by more than $30 million..." (Emphasis added). In fact, the Settlement Agreement provides to the contrary as correctly pointed out by CUCA. By this Order, the Commission has approved the language contained in the Settlement Agreement, thereby resolving the apparent conflict pointed out by CUCA.

markets. However, no suggestion was made or testimony offered to suggest that the coal purchasing practices of PEC were anything other than reasonable and prudent.

Nothing in the Settlement Agreement or this Order will preclude CUCA or the Attorney General from bringing forward any new rate design proposal or challenging the prudence of any of PEC's fuel expenses in subsequent years, while enjoying the benefits of the Agreement in the meantime. At this time, however, and based on the record in this proceeding, the Commission finds and concludes that the Settlement Agreement is just, reasonable and in the best interest of PEC's retail ratepayers and that no party to this proceeding will be aggrieved by an Order approving the Settlement Agreement and allowing it to remain in effect pursuant to its terms until it expires or is terminated.

As mentioned above, the terms of the Settlement Agreement include a provision for interest on under-recoveries arising because PEC agreed to a fuel factor below the factor justified in this case. This provision means that PEC should be allowed to charge and collect interest on the difference between the fuel factor agreed to by the parties to the Settlement Agreement and the fuel factor which PEC would otherwise be entitled to charge as a result of this proceeding. By charging a fuel factor which is substantially below the anticipated fuel cost during the time period rates established in this proceeding will be in effect, PEC is expected to experience under-recoveries during this time period. The Public Staff and CIGFUR II both agreed that PEC is entitled to interest on the under-recovery since PEC has agreed to a lower base fuel factor to help mitigate the customer impact on the rate change in this case.

In Docket No. E-2, Sub 784, the Commission approved a Stipulation Agreement between all the parties in the case with the exception of the Attorney General. That Stipulation Agreement provided for the accumulation of interest on the uncollected EMF amount that was deferred for recovery because PEC faced a similar situation involving a large fuel increase in the then current case. The Commission in that case approved an increase of $55.4 million and deferred recovery of another $55.46 million of prudently incurred test period fuel costs, that were eligible for recovery in that proceeding. In approving the Stipulation in that case, the Commission also approved the accrual of interest on the un-recovered amount during the 5-year recovery period. In that case, PEC was allowed to accrue interest on amounts deferred that it would otherwise have been entitled to recover.

The Commission agrees that PEC should be allowed to charge and collect 6% interest on an amount equal to the under-recovery resulting from PEC agreeing to a total fuel factor of 2.55¢/kWh in this case rather than a total fuel factor of 2.856¢/kWh (excluding gross receipts tax) until all such costs have been recovered as set forth in the Settlement Agreement. As explained earlier herein, no party challenged PEC's forecasted fuel costs or presented evidence that the provisions of the Settlement Agreement addressing the accrual of interest are unreasonable. Therefore, the Commission will allow PEC to accrue such interest each month at the annual rate of 6%, compounded annually. However, the Commission notes that the Settlement Agreement does not specifically address how and when the interest on the under-recovery will be recovered. Therefore, the Commission concludes that any future proposal for the recovery of such interest should be submitted for review and approval by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding can be found in the direct testimony of PEC witness Barkley and the testimony of Public Staff witness Edwards. Witness Barkley explained that PEC intended to charge or credit prudently-incurred natural gas costs and gains and losses associated with financial and physical hedging transactions to FERC Account Number 547 and treat them as recoverable fuel costs pursuant to G.S. 62-133.2. Examples of such items include transaction costs associated with derivatives, gains and losses on futures contracts, premiums on options contracts and net settlements of swaps transactions. Witness Barkley emphasized that these costs are an essential part of PEC's cost of fuel and purchasing strategy. As a result, such prudently incurred hedging costs and the associated natural gas costs should be fully recoverable as a fuel cost.

Public Staff witness Edwards testified that he generally agreed with PEC, provided the transaction costs in question were just and reasonable and prudently incurred and limited to direct, transaction-related costs arising from the Company's prudent efforts to stabilize or hedge natural gas costs.

In its brief, CIGFUR II states that PEC's Application did not include a request for a declaratory ruling that future transaction-related hedging costs be treated as fuel costs recoverable in future fuel charge adjustment proceedings. According to CIGFUR II, G.S. 62-133.2 limits fuel charge adjustments to those based on the cost of fuel and the fuel component of purchased power and PEC did not meet its burden of proving that transaction-related hedging costs are fuel costs within the contemplation of G.S. 62-133.2. CIGFUR believes that such costs are neither costs of fuel or costs of fabrication or transportation of fuel. Finally, CIGFUR II argues that any decision to allow additional costs to be passed through the fuel adjustment mechanism should be made only after a comprehensive review of a full and adequate record.

With regard to CIGFUR II's statement that PEC's Application did not include a request for a declaratory ruling that such hedging costs be treated as fuel costs recoverable in future fuel charge adjustment proceedings, PEC witness Barkley's pre-filed direct testimony clearly stated PEC's intention to treat such costs as recoverable fuel costs pursuant to G.S. 62-133.2 and Public Staff witness Edwards was also cross-examined by PEC counsel on this issue. No other party presented any evidence regarding this matter. More importantly, the Commission simply disagrees with CIGFUR II and agrees with PEC and the Public Staff that direct, transaction-related costs arising from the Company's prudent efforts to reduce the impact of natural gas price volatility on the Company's fuel costs should be recoverable as fuel costs pursuant to G.S. 62-133.2 subject to the same standards of reasonableness and prudence as other fuel costs incurred by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding can be found in the direct testimony of PEC witness Roberts.

The Company proposed increasing the MDC rating for Brunswick Unit No. 2 from 900 MWs to 937 MWs effective January 1, 2006. No party offered any testimony challenging this change; therefore the Commission accepts the MDC changes as proposed by the Company.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after October 1, 2006, PEC shall adjust the base fuel component in its North Carolina retail rates by an increment of 0.784 ¢/kWh (0.810 ¢/kWh including gross receipts tax) above the base fuel component approved in Docket No. E-2, Sub 537. Said increment shall remain in effect until changed by a subsequent Order of this Commission in a general rate case or fuel adjustment case.

2. That PEC shall establish an EMF Rider as described herein to reflect an increment of 0.490 ¢/kWh (0.506 ¢/kWh including gross receipts tax) for retail rate schedules and applicable riders. This Rider is to remain in effect for a 12-month period beginning October 1, 2006, and expiring September 30, 2007.

3. That, effective for service rendered on and after October 1, 2007, an EMF shall be derived based upon PEC's fuel cost under-recovery for the test year ending March 31, 2007, including any approved interest, and the prospective component of the fuel factor shall be equal to 2.675 ¢/kWh less the derived EMF.

4. That effective for service rendered on and after October 1, 2008, an EMF shall be derived based upon PEC's fuel cost under-recovery for the test year ending March 31, 2008, including any approved interest, and the prospective component of the fuel factor shall be equal to 2.75¢/kWh less the derived EMF.

5 The Settlement Agreement entered into by PEC, the Public Staff and CIGFUR II as shown in Appendix A is approved.

6. That PEC is allowed to accrue 6% interest on an amount equal to the difference between 2.550 ¢/kWh and 2.856 ¢/kWh applied to service rendered between October 1, 2006 and September 30, 2007 until such difference has been recovered; and further, any future proposal for the recovery of such interest shall be submitted for review and Commission approval.

7. That PEC shall file appropriate rate schedules and riders with the Commission to implement the fuel charge adjustment approved herein not later than seven (7) working days from the date of this Order.

8. That the prudently-incurred direct, incremental, transaction-related costs of financial and physical hedging activities utilized by PEC to reduce the volatility of its natural gas costs and charged or credited to FERC Account No. 547 shall be treated as recoverable fuel costs pursuant to G.S. 62-133.2 subject to the same standards of reasonableness and prudence as traditional fuel costs incurred by the Company.

9. That PEC shall provide CIGFUR II and the Public Staff quarterly reports beginning February 1, 2007 comparing the actual fuel cost under-recovery as of the close of the previous calendar quarter to the deferred amounts shown in Attachment 1, and such reports shall be filed by PEC with the Commission in this docket.

10. That PEC shall notify its North Carolina retail customers of the fuel charge adjustment approved herein by including the customer notice attached as Appendix B as a bill message to be

included on bills rendered during the Company's next normal billing cycle following the effective date of this Order.

11. That PEC and the Public Staff shall jointly develop a proposed public notice applicable to PEC's next fuel charge adjustment proceeding and file such notice in that docket at the time the Company files the Application.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of September, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr092506.01

Commissioner James Y. Kerr, II concurs in part and dissents in part.

Commissioner Robert V. Owens, Jr. dissents with respect to the majority decision regarding natural gas hedging costs. Commissioner Owens would not allow natural gas hedging costs to be recovered pursuant to G.S. 62-133.2 in fuel adjustment proceedings.

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REVISED ALTERNATE SETTLEMENT AGREEMENT

The North Carolina Utilities Commission Public Staff ("the Public Staff"), Carolina Industrial Group for Fair Utility Rates II ("CIGFUR"), and Progress Energy Carolinas, Inc. ("PEC") agree to settle PEC's 2006, 2007 and 2008 Fuel Cases on the following terms:

1) PEC's total fuel factors (exclusive of gross receipts tax) to be effective for the next three fuel cases, including the EMF, shall be as follows:

- Effective October 1, 2006: 2.55 cents per kWh
- Effective October 1, 2007: 2.675 cents per kWh
- Effective October 1, 2008: 2.75 cents per kWh

2) The term of this Settlement Agreement is July 5, 2006 through September 30, 2009.

3) PEC shall be allowed to charge and collect 6% interest on an amount equal to the under-recovery resulting from PEC agreeing to a total fuel factor of 2.55 cents per kWh in the 2006 case rather than a total factor of 2.856 cents per kWh (exclusive of gross receipts tax) until all such costs have been recovered.

4) If during the term of this Settlement Agreement PEC's monthly deferred fuel balance varies from the amounts shown in Attachment 1 to this Agreement by $30 million or more, any party may terminate the Agreement upon 30 days written notice.

5) During the three-year period addressed by this Agreement, the Commission shall continue to hold hearings pursuant to G.S. § 62-133.2(b) and Commission Rule R8-55(a) for the purpose of reviewing PEC's fuel expenses incurred during the relevant test periods. If, as a result of such

hearings, the Commission determines that any of PEC's actual fuel expenses incurred during the relevant test periods were imprudently incurred, the Commission may order PEC to make appropriate adjustments to its fuel expense accounts. Provided, however, such adjustment shall not affect PEC's authorized fuel factors as set forth above until PEC's next application for an adjustment to its fuel factor upon the expiration or early termination of this agreement, nor shall such adjustment be considered in determining whether PEC's monthly deferred fuel balance varies from the amounts shown in Attachment 1 to this agreement by $30 million or more.

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6) In the event the Commission determines that any of PEC's actual fuel expenses incurred during the relevant test periods were imprudently incurred, PEC shall not be allowed to charge and collect 6% interest on such amount. Accumulation of interest on the amounts shown in Attachment 1 shall not be considered in determining whether PEC's monthly deferred fuel balance varies from the amounts shown in Attachment 1 to this Agreement by $30 million or more.

7) PEC shall provide CIGFUR and the Public Staff quarterly reports beginning February 1, 2007 comparing the actual fuel cost under-recovery as of the close of the previous calendar year quarter to the deferred amounts contained in Attachment 1.

8) Upon the termination of this Agreement by a party, PEC shall, as soon as permitted by G.S. § 62-133.2, file an application for an adjustment to its fuel cost recovery factor and experience modification factor pursuant to G.S. § 62-133.2 and Commission Rule R8-55.

9) Unless this Agreement is terminated early pursuant to the terms of the Agreement, PEC shall file an application for an adjustment to its fuel cost recovery factor and experience modification factor pursuant to G.S. § 62-133.2 and Commission Rule R8-55 in June of 2009.

10) The parties agree that in PEC's next fuel case following the termination or expiration of this agreement, PEC shall be allowed to update its Application to seek recovery of its actual deferred fuel cost balance as of June 30 of that year.

11) To the extent the implementation of this Settlement Agreement requires a waiver of Commission Rule R8-55, all parties shall support such waiver or change.

12) Via a separate agreement, the parties will agree that PEC shall provide to the LGS-RTP rate class during the period October 1, 2006 through September 30, 2009, a credit to be applied against each RTP customer's actual kWh purchases. Such credit shall be calculated as follows:

> Credit = the sum of the following for all coal units during the time period April 1 through March 31 [(the amount of coal burned by unit on a mmbtu basis to make excess generation sales) multiplied by (the replacement price of coal at the time of the sale minus the stockpile average price, both expressed on a $/mmbtu, for the respective coal unit used to make excess generation sales)], where:

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- The fuel burned to make excess generation sales will be extracted by unit from the routine fuel credit calculation process.
- Replacement coal costs are based on the observed spot value of the commodity from an independent published source (currently Global Energy's Daily Coal Price Forecast), adjusted for applicable variable charges, to represent delivered cost. Exceptions may exist where the specific fuel type being utilized is not well represented by a published source. In such cases, quotes, market observations, or actual transactions may be used to arrive at the appropriate replacement price signal.
- Stockpile average prices are based on the weighted average delivered coal costs as recorded at the end of the prior month in the fuel management system.

The credit shall be distributed to the individual RTP customers via a decremental rider to each RTP customer's bill. The rider shall be adjusted annually. The decremental rider shall be calculated by dividing the aggregate credit calculated pursuant to the methodology described above by the annual kWh billed for the fuel case test year ended March 31 for Schedule LGS-RTP participants expected to receive service during the effective term of the rider. The decremental rider shall be rounded to the nearest thousands of a cent per kWh (i.e. $0.00XXX/kWh). No adjustment shall be made to actual sales for planned or past changes in consumption due to weather or other events. The decremental rider shall be applicable to the actual energy consumed and billed in the month, including both the energy consumed in the Customer Baseline Load as well as incremental usage subject to RTP hourly rates. The revenue associated with the Real Time Pricing Energy Rider shall be separately stated on the monthly bill. Upon termination of the Rider, there will not be a true-up of any difference between the decremental rider revenue and the "revenue reduction target."

The wording of the actual Rider to be submitted for approval by the North Carolina Utilities Commission shall be as follows:

REAL TIME PRICING ENERGY RIDER

A decremental rider of 0.XXX¢/kWh[1] shall be added to the Monthly Rate applicable to the Large General Service (Experimental - Real Time Pricing) Schedule LGS-RTP effective for bills rendered from October 1, 2006 through September 30, 2007.

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The decremental rider is applicable to the actual energy consumed and billed in the month, including both the energy consumed in the Customer Baseline Load as well as incremental usage subject to the RTP hourly energy charge.

This Settlement Agreement is entered into this 1st day of September, 2006.

Progress Energy Carolinas, Inc.
/s/ Len S. Anthony

[1] This decrement is not a part of the energy charges included in the energy prices stated in the LGS-RTP Schedule and should therefore be applied in addition to the rates stated in the schedule.

North Carolina Utilities Commission Public Staff
/s/ Antoinette R. Wike

Carolina Industrial Group for Fair Utility Rates II
/s/ Carson Carmichael

APPENDIX A
ATTACHMENT 1

PEC
DEFERRED ACCOUNT PROJECTIONS

Month	Year	Projected mwhs	Projected cost/kwh	Settled rate/kwh	Monthly Change($M)	Account Balance ($M)
Beginning						325
October	2006	2,868,400	1.927	2.314	(11)	314
November	2006	2,632,566	1.895	2.550	(17)	297
December	2006	3,124,585	2.153	2.550	(12)	284
January	2007	3,384,408	2.083	2.550	(16)	268
February	2007	3,207,019	2.296	2.550	(8)	260
March	2007	2,971,102	2.160	2.550	(12)	249
April	2007	2,798,963	2.023	2.550	(15)	234
May	2007	2,817,473	2.363	2.550	(5)	229
June	2007	3,235,053	2.524	2.550	(1)	228
July	2007	3,620,237	3.320	2.550	28	256
August	2007	3,740,206	2.962	2.550	15	271
September	2007	3,516,689	2.375	2.550	(6)	265
October	2007	2,924,633	2.321	2.613	(9)	256
November	2007	2,683,607	2.129	2.675	(15)	242
December	2007	3,188,067	2.255	2.675	(13)	228
January	2008	3,451,535	2.144	2.675	(18)	210
February	2008	3,269,356	2.081	2.675	(19)	191
March	2008	3,028,117	2.289	2.675	(12)	179
April	2008	2,851,515	1.863	2.675	(23)	156
May	2008	2,870,440	2.135	2.675	(16)	140
June	2008	3,296,778	2.649	2.675	(1)	139
July	2008	3,691,019	3.392	2.675	26	166
August	2008	3,813,359	2.933	2.675	10	176
September	2008	3,584,854	2.185	2.675	(18)	158
October	2008	2,979,824	2.357	2.713	(11)	148
November	2008	2,733,766	2.033	2.750	(20)	128
December	2008	3,250,452	2.332	2.750	(14)	114
January	2009	3,519,489	2.175	2.750	(20)	94
February	2009	3,332,578	2.188	2.750	(19)	75
March	2009	3,086,011	2.340	2.750	(13)	63
April	2009	2,904,980	2.363	2.750	(11)	52
May	2009	2,924,319	2.203	2.750	(16)	36
June	2009	3,359,474	2.477	2.750	(9)	26
July	2009	3,762,753	2.960	2.750	8	34
August	2009	3,887,491	2.615	2.750	(5)	29
September	2009	3,653,989	2.082	2.750	(24)	5

APPENDIX B

PEC BILL MESSAGE

The N. C. Utilities Commission issued an Order on September 25, 2006, after public hearings and review, approving a fuel charge increase of approximately $177 million in the rates and charges paid by North Carolina retail customers of Progress Energy Carolinas, Inc. The rate increase will be effective for service rendered on and after October 1, 2006, and will result in a monthly rate increase of $4.87 for a typical customer using 1,000 kWh per month.

DOCKET NO. E-2, SUB 889

COMMISSIONER JAMES Y. KERR, II, DISSENTING IN PART: I dissent from those parts of the majority's decision that approve the Revised Alternate Settlement Agreement. I cannot join my colleagues in this decision because I believe that the settlement violates the legal requirements of the fuel charge adjustment statute, denies fundamental requirements of due process in Commission proceedings, and is unwise. While I appreciate the efforts of the settling parties to resolve their differences and understand the inclination of my colleagues to choose the path of least resistance, I consider the legal and policy flaws reflected in their approach to be too important to ignore. Accordingly, I believe that the application of PEC should be approved as filed.

The fuel charge adjustment statute, G.S. 62-133.2, was enacted by the General Assembly to provide a method and procedure for the recovery of an electric utility's reasonable and prudently incurred fuel costs. The statute provides for annual proceedings to review those costs and to approve an increment or decrement to base rates that will remain in effect until changed in a general rate case or in the next annual fuel adjustment proceeding. PEC's application proposed such a fuel factor calculated according to the statute, but the partial settlement does not comply with the statute. Instead, the partial settlement establishes fuel factors not only for the present 2006 fuel proceeding, but also for the 2007 and 2008 fuel proceedings. Together, these factors are intended to allow PEC to recover, over a three-year period, both its forecasted fuel costs and its under-recovery of fuel costs through September 30, 2006. I am confident that this partial settlement was well-intentioned, but I believe that it presents serious legal problems.

The majority claims legal authority for its decision, but it never says exactly where this authority lies in the General Statutes. The fuel charge adjustment statute makes no provision for establishing fuel factors three years into the future, and the Commission has only such authority as granted to it by the General Assembly. State ex rel. Utilities Comm. v. Southern Bell Tel. & Tel. Co., 307 NC 541 (1983). Further, PEC's application in this docket made no mention of setting fuel factors for the 2007 and 2008 fuel cases, and the public notice published for this proceeding gave no notice that such would be considered. Application and notice are fundamental concepts of due process.

Next, the Commission's decisions must be supported by competent, material, and substantial evidence. G.S. 62-94(b)(5). In this case, the only evidence of PEC's future fuel expenses for establishing the 2007 and 2008 fuel factors is a column of "Projected cost/kwh" on Attachment 1 to the original settlement agreement. No PEC witness sponsored this exhibit, and the Public Staff witness who sponsored the original settlement agreement at the hearing, and presumably this exhibit, failed to provide substantial evidence in support of the agreement. There is at least a question in my mind as to whether the record is sufficient to allow the Commission to make "an independent determination supported by substantial evidence on the record" as to the appropriate fuel factors for the 2007 and 2008 fuel proceedings. See and compare State ex rel. Utilities Comm. v. Carolina Utility Customers Assn., 351 NC 223, 229-32 (2000).

There is no question in my mind that there is insufficient evidence to allow the Commission to approve the Revised Alternate Settlement Agreement, and the substantive changes contained therein. The Revised Alternate Settlement Agreement (which made substantive changes to the original settlement agreement) was not filed with the Commission until September 1, 2006, well after the close of the hearing. A settlement entered into by less than all of the parties to a proceeding is different from mere argument in a post-hearing brief or proposed order. Such a settlement is evidence, not argument. Such a settlement cannot be used for informal disposition of a contested proceeding under G.S. 62-69(a); rather, such a settlement must be considered by the Commission "with all other evidence presented by any of the parties in the proceeding." State ex rel. Utilities Comm. v. Carolina Utility Customers Assn., 348 NC 452, 466 (1998) (emphasis added). When evidence is received after the close of a hearing, any non-settling party "[u]nquestionably...had the right, unless waived, to demand that the hearing be reopened, in order to permit it to cross-examine witnesses...or to offer evidence of its own in rebuttal." Utilities Comm. v. Telegraph Co., 267 NC 257, 269 (1966). CUCA has requested that the hearing be re-opened, and I believe that the law requires such before the Revised Alternate Settlement Agreement can be approved. While it is not clear to me why one advocate for industrial consumers supports a settlement intended to phase in the rate impact of the fuel charge adjustment PEC is entitled to, and the other advocate for industrial consumers opposes it, it is CUCA's legal right to do so and to request that the hearing be reopened.

PEC and the Public Staff, joined by the majority, respond to these obvious concerns by essentially resorting to a game of "legal Twister." They cite G.S. 62-80 and argue that the Commission "on its own motion or upon the motion of an entity that was not a party to the Settlement Agreement, may rescind, alter or amend the Commission's Order in this proceeding." This argument is illogical and does not solve the problem. The possibility of reconsideration under G.S. 62-80 cannot be used to excuse non-compliance with proper procedure in the first place. Indeed, reliance upon G.S. 62-80 compounds the error. PEC and the Public Staff would require other parties to seek reconsideration as to fuel factors which have been set contrary to G.S. 62-133.2 and due process. A proceeding for reconsideration of a Commission order under G.S. 62-80 is a very different animal -- in terms of procedure, burden of proof, and appeal -- than a fuel adjustment proceeding under G.S. 62-133.2, and reconsideration simply cannot substitute for a proper fuel adjustment proceeding in the first place. Following this argument to its logical conclusion, the majority would have G.S. 62-80 act as a blanket excuse from compliance with all other provisions of Chapter 62. Surely this is not the appropriate application of G.S. 62-80.[1]

The Attorney General points out that the Commission is not required to set the fuel factor "solely and strictly 'by the numbers.'" This is true; however, the flexibility that G.S. 62-133.2 wisely

[1] This reliance to G. S. 62-80 raises an interesting question. What kind of notice does the majority intend to give the public in PEC's next two fuel cases? The 2007 and 2008 fuel factors have been set in this case. Therefore, the standard public notice used for fuel proceedings would not accurately reflect the status of the 2007 and 2008 proceedings. Does the majority intend to tell the public in the 2007 and 2008 proceedings that PEC's fuel factor has already been set one or two years before and that the burden has been shifted to them to show why the previously approved fuel factor should be reconsidered?

affords the Commission in weighing the evidence in a fuel case cannot be invoked to disregard the procedures required by that statute, by due process, and by the decisions of our appellate courts.

In summary, the partial settlement approved by the majority violates the fuel adjustment statute and due process, and I cannot overcome this objection by deferring to some of the consumer advocates' judgment to the contrary or by simply hoping that CUCA will not appeal. Commissioners are appointed to exercise their independent judgment, not to go along with whatever is presented to them.

In addition to these significant legal problems, I believe that the settlement is unwise as a matter of policy. First, the success of the settlement depends upon the accuracy of PEC's projections of fuel expenses for three years into the future. However, as discussed above, PEC did not present any expert testimony supporting such projections beyond one year, and it is undeniable that such long-range projections are inherently uncertain. We need only look to PEC's recent experience (which has led to an under-recovery of over $300 million) to understand the difficulty of predicting fuel expenses accurately just one year in advance, much less three years.

Second, I am concerned about the interest obligation that the partial settlement imposes upon ratepayers. G.S. 62-133.2 provides for truing-up under-recoveries (or over-recoveries) year by year as they occur and does not require ratepayers to pay interest to the utility. The settlement approved by the majority allows PEC to charge and collect 6% interest on its under-recovery "until all such costs have been recovered," and this can add up to a substantial sum.[1] Commission Staff estimates that such interest could amount to approximately $30 million. Given that PEC is entitled to recover its prudently incurred fuel costs on an annual basis, any deferral of such recovery appropriately should include interest. Thus, it is not the payment of interest that is objectionable; it is the deferral itself and the accompanying substantial additional costs imposed on ratepayers that is unwise and unnecessary.

Third and most important, I simply believe that the time has come to face the under-recovery of PEC's fuel costs squarely. PEC is entitled to recover its reasonable and prudently incurred fuel costs. In recent years, PEC and various intervenors have entered into partial settlements, subsequently approved by the Commission, which have had the effect of contributing to under-recoveries in successive cases. The 2001 partial settlement added almost $3.5 million in under-recovery and $11 million in interest to the fuel costs which are to be recovered in the present case.[2] The 2005 partial settlement set PEC's fuel factor lower than what was justified by the evidence, and that has contributed to the massive under-recovery that we now face.[3] The present partial settlement continues this practice: it potentially creates an interest expense extending into the 2009 fuel case,

[1] This imposition of interest alone is arguably enough to render CUCA an aggrieved party. Compare State ex rel. Utilities Comm. v. Carolina Utility Customers Assn., 104 NCApp 216 (1991).

[2] In its 2001 fuel case, PEC agreed to spread $55.46 million of its under-recovery over the succeeding five fuel cases, and the Commission agreed. 91st Report of NCUC Orders and Decisions 255 (2001). It is worth noting that that decision, in which I joined, did not establish fuel factors for those future cases (as does this one), but only carried over expenses into the future cases. Also, in the 2001 fuel case, PEC agreed to write off any unrecovered balance at the end of the five-year period. PEC has made no such commitment here.

[3] The Commission stated in that proceeding that its decision "will, in all probability, cause PEC to significantly under-recover its fuel casts...," and that has proven all too true. 95th Report of NCUC Orders and Decisions 185, 203 (2005).

and it provides that any disallowance for imprudence ordered in connection with the 2007 and 2008 fuel cases will not even be reflected in rates until the 2009 fuel case.

When natural gas prices spiked in recent years, the Commission followed the rate adjustment procedures prescribed by statute and did what was required. Natural gas rates rose, and hardship undoubtedly ensued, unfortunately. But the higher rates sent consumers appropriate price signals as to the economic environment of the time and as to the utility's costs, and natural gas prices and rates have since abated. The majority's decision to accept the partial settlement in this case sends misleading price signals to PEC's customers for years to come, and it does so at a time when the Commission is trying, in other contexts, to encourage energy efficiency and conservation.

I do not minimize the difficulty that consumers would experience this year under the result that I advocate, and I understand the majority's desire for a phase-in. But, in reality, the phase-in does not provide any rate relief. The immediate rate impact approved by the majority is $4.87 per 1000 kWh, as opposed to $8.05 per 1000 kWh under PEC's original proposal, but the difference is not forgiven; it will be recovered with interest over the succeeding two years. In reality, the majority is merely postponing the inevitable, and the cost of its doing so is high --a significant interest obligation, perpetuation of PEC's underrecovery of fuel costs, and misleading price signals for consumers. Moreover, it is my belief that there are other issues lurking on the horizon that cannot be avoided and which will put upward pressure on rates.

The majority tries to cover its decision herein with advice to future Commissioners to follow proper procedure and avoid deferrals and phase-ins, all to be done tomorrow. With all due respect and the utmost admiration for my colleagues, these decisions will not be any easier tomorrow and it is a disservice to those we serve not to deal with them today. The Commission is unlikely to ever see another partial settlement more violative of proper procedure than this one. Now, if ever, is the time to stand on principle.

\s\ James Y. Kerr, II
Commissioner James Y. Kerr, II

DOCKET NO. E-7, SUB 805

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Power, a Division of Duke Energy Corporation Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, May 2, 2006, at 10:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin IV, Presiding; Commissioner Lorinzo L. Joyner; and Commissioner William T. Culpepper III

APPEARANCES:

For Duke Power Company LLC, d/b/a Duke Energy Carolinas, LLC:

Lara S. 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., 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney, Tab C. Hunter, 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.:

James P. West, West Law Offices, P.C., Suite 1735, 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

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 3, 2006, Duke Power, a division of Duke Energy Corporation (now Duke Power Company LLC, d/b/a Duke Energy Carolinas, LLC) (hereinafter Duke 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 charge adjustments for electric utilities.

On March 8, 2006, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice.

On March 10, 2006, the Carolina Industrial Groups for Fair Utility Rates III (CIGFUR III) filed a petition to intervene, and the petition was allowed by the Commission on March 20, 2006. On March 22, 2006, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, and the petition was allowed by the Commission on March 29, 2006. The intervention of the Public Staff is recognized pursuant to Commission Rule R1-19(e). On April 13, 2006, Roy Cooper, Attorney General, filed a notice of intervention. The intervention of the Attorney General is recognized pursuant to G.S. 62-20.

On April 19, 2006, the Public Staff filed a notice of affidavits and the affidavits of Thomas S. Lam, Utilities Engineer, Electric Division, and Darlene P. Peedin, Staff Accountant, Accounting Division. On May 2, 2006, CUCA gave notice pursuant to G.S. 62-68 that it wished to cross-examine the Public Staff witnesses.

On April 26, 2006, Duke filed the supplemental testimony of Janice D. Hager.

On May 1, 2006, Duke filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as ordered on May 2, 2006. M. Elliott Batson, Manager, Coal and Bulk Material Procurement, and Janice D. Hager, Vice President, Rates and Regulatory Affairs, presented direct testimony for the Company. Darlene P. Peedin, Staff Accountant, Accounting Division presented direct testimony on behalf of the Public Staff. The Commission admitted into evidence the affidavit of Thomas S. Lam, Utilities Engineer, Electric Division, following CUCA's waiver of its right to cross-examine him. No other party presented witnesses, and no public witnesses appeared at the hearing.

After the hearing, the parties filed briefs and proposed orders on May 26, 2006, as allowed by the Commission.

On June 1, 2006, the Commission issued an order allowing any party to file a reply brief. On June 8, 2006, the Company filed a reply brief.

Finally, on June 26, 2006, the Company filed exhibit pages that had been inadvertently omitted when the supplemental testimony of Janice D. Hager was filed with the Commission's Clerk on April 26, 2006. The exhibit pages had been served on the parties on April 26, 2006, and they were admitted into evidence at the hearing. No party objected to this late filing of the exhibit pages with the Clerk.

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 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 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, 2005.

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

4. The test period per book system sales are 78,776,140 MWh.

5. The test period per book system generation is 90,784,256 MWh and is categorized as follows:

Generation Type	MWh
Coal	46,572,280
Oil and Gas	74,384
Light Off	-
Nuclear	40,545,294
Hydro	1,841,017
Net Pumped Storage	(858,150)
Purchased Power	1,180,806
Catawba Interconnection Agreements	1,244,200
Interchange	184,425
Total Generation	90,784,256

6. The nuclear capacity factor appropriate for use in this proceeding is 90%.

7. The adjusted test period system sales for use in this proceeding are 78,616,204 MWh.

8. The adjusted test period system generation for use in this proceeding is 90,104,290 MWh and is categorized as follows:

Generation Type	MWh
Coal	48,389,480
Oil and Gas	101,476
Light Off	-
Nuclear	39,579,650
Hydro	1,682,200
Net Pumped Storage	(829,322)
Purchased Power	1,180,806
Total Generation	90,104,290

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

A. The coal fuel price is $26.68/MWh.
B. The oil and gas fuel price is $160.37/MWh.
C. The appropriate Light Off fuel expense is $9,837,000.
D. The nuclear fuel price is $4.38/MWh.
E. The nuclear fuel price for Catawba generation is $4.23/MWh.
F. The purchased power fuel price is $22.66/MWh.
G. The adjusted level of fuel credits associated with intersystem sales is $198,755,000.

10. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 50% of the energy portion of the purchase price is reasonable for use in this proceeding.

11. The adjusted test period system fuel expense for use in this proceeding is $1,318,414,000.

12. The appropriate fuel factor for this proceeding is 1.6770¢/kWh, excluding gross receipts tax.

13. The Company's North Carolina test period jurisdictional fuel expense over-collection was $3,731,000. The pro forma North Carolina jurisdictional sales are 54,338,729 MWh.

14. The Company's Experience Modification Factor (EMF) is a decrement of 0.0069¢/kWh, excluding gross receipts tax.

15. Interest expenses associated with over-collection of test period fuel expenses during the test period amount to $560,000 based upon a 10% annual interest rate.

16. The EMF interest decrement is 0.0010¢/kWh, excluding gross receipts tax.

17. The final net fuel factor produced by these Findings of Fact to be billed to Duke's North Carolina retail customers during the 2006-2007 fuel clause billing period is 1.6691¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 1.6770¢/kWh, the EMF decrement of 0.0069¢/kWh, and the EMF interest decrement of 0.0010¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending December 31 as the test period for Duke. The Company's filing was based on the 12 months ended December 31, 2005.

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 ended December 31, 2005. In addition, the Company files monthly reports of its fuel costs pursuant to Commission Rule R8-52(a).

Duke witness Batson described the Company's fuel procurement practices. These practices include estimating fuel requirements, establishing appropriate inventory requirements, monitoring on-going fuel requirements, developing qualified supplier lists, bid evaluation, balancing long term contracts and spot purchases, expediting/monitoring purchases, and on-going quality control.

In its brief, CUCA recommends that the Commission disallow $49.7 million in fuel costs due to Duke's failure to engage in prudent coal purchasing practices during the test period. CUCA contends that (1) Duke neglected to adequately diversify its coal supply sources and (2) Duke unreasonably incorporated excessive emission allowance prices in comparison studies of its coal supply options in order to justify purchases of expensive low sulfur coal and avoid using emission allowances and making capital improvements. CUCA states that the incurrence of higher coal expenses instead of using emission allowances or making capital improvements allows Duke to attempt to recover most costs from ratepayers through fuel charge adjustment proceedings and leaves fewer costs to be borne by shareholders until its next general rate case. CUCA calculates the $49.7 million recommended disallowance by reducing Duke's fuel expense for coal consumed during the test period, which was $994.5 million, by 5%. CUCA argues that the 5% reduction is appropriate considering the coal costs incurred by certain other utilities in Duke's region.

CUCA's brief relies heavily on certain information from Duke's 2006 Duke Power Fuels Management Ten-Year Assessment and Plan, identified in the record as CUCA Batson Cross-Examination Exhibit No. 1. Using information in this confidential exhibit, CUCA essentially argues that Duke burned only Central Appalachia coal in 2005, excluding small amounts of non-Central Appalachia coal used in test burns, and that Duke was imprudent to reply upon this single source of coal.

In response to questions from counsel for CUCA, Duke witness Batson explained the transportation and operational issues associated with using non-Central Appalachia coal. In connection with developing its 2006 Fuel Management Ten-Year Assessment & Plan, Duke benchmarked its coal costs against those of other utilities within and outside the Southeast. Witness Batson described the geographic and transportation differences between the Company and the other utilities in the assessment that led to Duke's continued reliance on Central Appalachia coal, given the delivered cost of various coals to the Company and environmental restrictions on the Company's emissions. Witness Batson testified that the Company continually evaluates the market conditions for non-Central Appalachian coal, even if Duke does not receive offers from the market through an RFP process.

Witness Batson testified that Duke's coal-fired generation plants were designed to burn Central Appalachia coal. To burn other types of coal on a regular basis, the Company would need to make significant capital improvements, such as installing coal-blending facilities, installing soot blowers to address slagging, and making coal handling improvements and other equipment modifications, including modifications to boilers and coal mills. Witness Batson explained that higher sulfur coal in particular has a lower ash fusion temperature than the coal the units were designed to burn. The result is the creation of "slag" that clings to the sides of the boilers and boiler tubes, cakes up, and can form large clinkers that increase the possibility of forced outages. Further, due to environmental restrictions, the Company cannot burn Northern Appalachian or Illinois Basin coals other than in very small percentages until scrubbers are installed and operational. Witness Batson also testified concerning the transportation difficulties which Duke had encountered in its attempts to diversify its coal supply. He testified that it generally took Duke some period of time to get the railroads to develop the infrastructure and get crews in place to deliver coal from a new coal supply region to Duke's plants. For example, he stated that Duke had been working with a railroad for a couple of years to be able to get deliveries under a Northern Appalachia coal supply agreement starting in 2007. According to Batson's testimony, the Company reasonably and appropriately evaluates the use of non-Central Appalachian coals on a total cost basis, considering the fuel cost on a delivered basis, any increased operation and maintenance costs, and the cost of any capital modifications that would be required.

Additional evidence concerning Duke's initiatives and efforts to diversify its coal supply and purchase less expensive coal is discussed below in the Evidence and Conclusions for Finding of Fact No. 9.

After review of the evidence in this case relevant to CUCA's argument that Duke neglected to adequately diversify its coal supply sources, the Commission concludes that the Company's coal purchasing practices were reasonable during the test period. Duke witness Batson testified that the Company continually evaluates non-Central Appalachia coal, considering commodity and delivery costs as well as transportation and operational constraints. CUCA submitted no evidence pointing to any specific coal purchase transaction entered by Duke during the test year, or coal purchasing opportunity foregone, in support of its imprudency argument. CUCA relies heavily on comparisons of the cost of coal between Duke and certain other utilities. While such benchmark comparisons can be useful, evidence in the record also demonstrates that there are differences in plant design and coal supply options which affect coal costs. Therefore, differences in coal costs between utilities, without more, do not constitute sufficient evidence upon which to predicate a finding of imprudence.

As noted above, CUCA also takes the position that Duke unreasonably incorporated excessive emission allowance prices in comparison studies of its coal supply options in order to justify expensive low sulfur coal purchases and avoid using emission allowances or making capital improvements. More specifically, CUCA argues that the Company should use the book cost of its emission allowances in inventory, rather than market prices of emission allowances (which have been escalating), to adjust coal cost comparisons for SO2 content in its evaluation of coal purchases from various suppliers.

The Commission finds it unnecessary to decide this issue in this proceeding. First, transportation and operational constraints clearly limited the Company's ability to purchase high sulfur coal from suppliers outside the Central Appalachia region even if it had wanted to do so. Further, Duke witness Batson maintained that Duke's use of the current market price for emission allowances is appropriate for making economic evaluations of incremental coal purchases. CUCA presented evidence of no particular coal purchasing decision which should have changed, based on cost considerations alone, if the Company had used the book cost of its emission allowances, and Duke witness Batson testified that he was not sure whether the Company's purchase decisions would have changed if it had used a different emission allowance price. Given the evidence in this record, the Commission cannot determine that this issue affected Duke's coal purchase decisions or cost of coal during the test period. In Utilities Commission v. Intervenor Residents, 52 N.C.App. 222 (1981), reversed 305 N.C. 62 (1982), as in the present proceeding, there was testimony from a utility witness that the expenses in question were reasonable and this testimony was not contradicted or challenged by any other witness. "No party offered any evidence to refute this testimony nor even any evidence tending to show that the costs allocated to the Company were unusual in any way or unreasonable...." 305 NC at 75. The Supreme Court re-affirmed that the burden of persuasion as to the reasonableness of expenses "always rests with the utility," but the Supreme Court went on to state that, "in the absence of contradiction or challenge by affirmative evidence offered by any party to the proceeding, the Commission has no affirmative duty to make further inquiry or investigation into the reasonableness of charges or fees paid to affiliated companies." Id. The Supreme Court concluded that the "burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses..." 305 N.C. at 76. The Commission finds no evidence in this proceeding to support CUCA's argument. Should this issue arise in future fuel adjustment proceedings, the Commission will decide the matter based on the record in those proceedings.

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

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

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

Company witness Hager testified that the test period per book system sales were 78,776,140 MWh and test period per book system generation was 90,784,256 MWh. The test period per book generation is categorized as follows:

Generation Type	MWh
Coal	46,572,280
Oil and Gas	74,384
Light Off	-
Nuclear	40,545,294
Hydro	1,841,017
Net Pumped Storage	(858,150)
Purchased Power	1,180,806
Catawba Contract Purchases	-
Catawba Interconnection Agreements	1,244,200
Interchange	184,425
Total Generation	90,784,256

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

Witness Hager testified that Duke achieved a system average nuclear capacity factor of 93.68% for the test period and that the most recent (2000-2004) NERC five-year average nuclear capacity factor for all pressurized water reactor units is 88.46%. The affidavit of Public Staff witness Lam also included this information. Witness Hager recommended a nuclear capacity factor of 90% for use in setting the fuel rate in this proceeding, based on the operational history of the Company's nuclear units and the number of outage days scheduled for the billing period.

By recommending Commission approval of Duke's proposed fuel factor, Public Staff witness Lam implicitly agreed with the Company's per books sales and generation levels of 78,776,140 MWh and 90,784,256 MWh, respectively, as well as Duke's recommended nuclear capacity factor of 90%. No other party contested these amounts.

Based upon the agreement of the Company and the Public Staff as to the appropriate levels of per book system MWh generation and sales, and noting the absence of evidence presented to the contrary, the Commission concludes that the levels of per book system sales of 78,776,140 MWh and per book system generation of 90,784,256 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 system, the agreement of the Public Staff, and the absence of evidence to the contrary, the Commission concludes that the 90% nuclear capacity factor and its associated generation of 39,579,650 MWh, excluding the Catawba Joint Owners' portion of said generation, are reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

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

The evidence for these findings of fact is found in the testimony of Company witness Hager.

Witness Hager made an adjustment of a negative 159,936 MWh and a negative 679,966 MWh to per book system sales and generation, respectively, to normalize for weather, customer growth, the Catawba Interconnection Agreements, and line losses/Company use, based on a 90% normalized system nuclear capacity factor. She, therefore, calculated an adjusted system sales level of 78,616,204 MWh and an adjusted system generation level of 90,104,290 MWh.

By recommending Commission approval of Duke's proposed fuel factor, Public Staff witness Lam implicitly accepted witness Hager's adjusted sales and generation levels of 78,616,204 MWh and 90,104,290 MWh, respectively. No party contested the Company's adjustments for weather normalization, customer growth, Catawba retained generation, or line losses/Company use.

The Commission concludes, after finding a system nuclear capacity factor of 90% reasonable and appropriate in Finding of Fact No. 6, that the adjustment to per books system generation of a negative 679,966 MWh and the resulting adjusted test period system generation level of 90,104,290 MWh are both reasonable and appropriate for use in this proceeding. Total adjusted generation is categorized as follows:

Generation Type	MWh
Coal	48,389,480
Oil and Gas	101,476
Light Off	-
Nuclear	39,579,650
Hydro	1,682,200
Net Pumped Storage	(829,322)
Purchased Power	1,180,806
Total Generation	90,104,290

The Commission also finds the adjusted sales level of 78,616,204 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 and Hager.

Company witness Batson testified regarding Duke's fossil fuel costs during the test year and changes expected in 2006. Witness Batson described market conditions in the spot and contract coal markets during the test year and the increasing costs of coal in the current market due to increasing domestic and international demand for coal, limited production response to this increased demand (especially in Central Appalachia), continuing strong export market conditions for Central Appalachia coal, increasing mining operating costs, high natural gas prices, and transportation complexities associated with alternative coal sources. Duke benefited from favorably priced coal contracts negotiated in previous years, which resulted in significantly lower average coal mine costs in the test year compared to prevailing market prices. During the test period, the Company continued to purchase synthetic fuel from facilities at Duke's Belews Creek and Marshall steam stations under the arrangements addressed in the fuel proceedings in Docket Nos. E-7, Sub 780 and E-7, Sub 746, resulting in savings of over $14 million in 2005.

Witness Batson further testified that, as Duke's existing coal contracts expire, they will be replaced at market prices significantly higher than what they have been in the past few years. Current market prices used by the Company in calculating its proposed fuel factor are based on new coal contracts entered into in late 2005, recent unsolicited offers from several producers, and forward coal prices as published by coal brokers that indicate Central Appalachia coal prices for the balance of 2006 and first half of 2007 in the low to upper $50s per ton for contract arrangements. This data indicates that the Company's cost of coal will be increasing in 2006 compared to 2005, although Duke's average cost of coal will be below the projected market price for Central Appalachia coal in 2006.

Witness Batson testified that average coal transportation costs increased in the test year due to increases in fuel surcharges applied by the railroads as a result of increasing fuel oil prices and tariff and contractual escalations relating to freight rates paid in 2005. For the test year, transportation costs constituted 31% of the Company's total delivered cost of coal. The Company expects that fuel surcharges will continue to apply in 2006 as fuel oil prices remain high.

Witness Batson also testified as to the Company's settlement of rate case complaints Duke initiated at the Surface Transportation Board (STB) concerning the freight rates Norfolk Southern Railway Company (Norfolk Southern) and CSX Transportation (CSX) charged the Company. In June 2005, Duke reached settlements with both railroads and entered into new transportation contracts. Key terms of the agreement with Norfolk Southern include a lump sum cash payment, which Duke received and credited against fuel expense, and a multi-year rail transportation contract with rates comparable to tariff rates the Company was paying. Key terms of the agreement with CSX include a multi-year rail transportation contract with rates slightly below the tariff rates the Company was paying for captive coal plants, an extension of coal deliveries to its Marshall steam station at competitive terms, and the provision of new rates for non-Central Appalachia coal sources to all of Duke's steam stations on the CSX system that have enhanced coal supply flexibility. Witness Batson stated that the primary benefit of reaching settlements and multi-year agreements with the railroads is the elimination of exposure to Norfolk Southern's and CSX's unlimited authority to increase rates upon 20 days notice.

Witness Batson testified that the Company is pursuing several initiatives that will limit exposure to regional coal market price increases and help control and stabilize coal costs in general. The Company continues to take action to enhance a comprehensive coal procurement strategy that reduces the risk of the extreme price volatility that can be seen in the coal market. Aspects of this strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations such that the Company is not in the position of replacing a significant percentage of contracts at any one time, and pursuing contract extension options that provide flexibility to extend terms within a price collar.

Further, witness Batson testified about the Company's efforts to develop the ability to burn non-Central Appalachia coal in the future to take advantage of market opportunities to purchase less expensive coal as these opportunities arise. Duke performed test burns on several non-traditional coals in 2005 and early 2006, including coals from Wyoming's Powder River Basin, Pennsylvania's Northern Appalachia Basin, and imported coal from South America. Witness Batson further testified that the Company will continue to evaluate operational and maintenance plant issues associated with the use of non-Central Appalachia coal, as permitted given environmental restrictions, and will communicate with the appropriate railroads the need to develop appropriate infrastructure to deliver this coal. This market and operational evaluation will analyze current and future opportunities to diversify the Company's coal supply with the result being able to provide on-going flexibility to take advantage of purchase opportunities in changing domestic and international market conditions. In 2005, the Company installed a coal blending system at its Marshall plant so that it would be in a position to take advantage of coal blending opportunities when the Company's first scrubbers at that facility come on line. Witness Batson stated that the Company expects that non-Central Appalachia coals could represent as much as 15% of Duke's total coal supply in 2007 as coal and rail market conditions develop and stabilize. Given infrastructure improvements that will increase the capacity at the port in Charleston, South Carolina, Duke will begin receiving coal from South America in May 2006. Additionally, Duke has obtained competitive rail rates on the CSX system to its plants from new coal sources and has entered into a supply agreement for Northern Appalachia coal beginning in 2007.

Duke witness Hager testified that, during the test year, the fossil steam generating plants provided approximately 52% of the Company's total generation and that the heat rate for these units was 9,528 BTU/MWh. Achievement of this heat rate continues Duke's consistent track record of operating the most efficient fossil-fired units in the country.

Witness Hager recommended fuel prices and expenses as follows:

A. The coal fuel price is $26.68/MWh.
B. The oil and gas fuel price is $160.37/MWh.
C. The appropriate Light Off fuel expense is $9,837,000.
D. The nuclear fuel price is $4.38/MWh.
E. The nuclear fuel price for Catawba generation is $4.23/MWh.
F. The purchased power fuel price is $22.66/MWh.
G. The adjusted level of fuel credits associated with intersystem sales is $198,755,000.

By recommending Commission approval of Duke's proposed fuel factor, Public Staff witness Lam implicitly agreed with the Company's proposed fuel prices and expenses.

Based upon the evidence in the record as to the appropriate fuel prices and expenses, the Commission concludes that the fuel prices recommended by witness Hager and accepted by the Public Staff are reasonable and appropriate for purposes of 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 Peedin and the exhibits of Company witness Hager.

Public Staff witness Peedin's affidavit stated that one of its purposes was to present her calculation of the appropriate fuel-to-energy percentage to be applied to the fuel costs associated with power marketers and other suppliers who supplied power to the Company during the test year. Witness Peedin indicated that, in order to determine this percentage, the Public Staff had performed an analysis of the fuel component of off-system sales made by Duke, Virginia Electric and Power Company 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, 2005. This analysis is similar to that performed by the Public Staff for the 1997 Stipulation addressing this matter (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 2005 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 Peedin stated that 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's 1996 fuel adjustment 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 (June 21, 1996).

Public Staff witness Peedin stated 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 the analysis for this proceeding meets the criteria set forth in the 1996 Duke Order.

As part of its current review, the Public Staff analyzed the off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 45.33%

to 57.67%, as set forth on Peedin Exhibit II. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel percentage should be 50% for purposes of this proceeding.

The Commission concludes, as it has in past dockets, 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 costs, is reasonable and satisfies the requirements set forth in the 1996 Duke fuel case order for purposes of this proceeding. First, the results of applying the methodology can be accepted under G.S. 62-133.2. As Public Staff witness Peedin 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 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 Peedin'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 that 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 relevant sellers of power to Duke. 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 fuel case order and is reasonable for purposes of this proceeding as the method of determining the proxy fuel cost.

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 45.33% to 57.67% and, based on its analyses, the Public Staff concluded that 50% is an appropriate and reasonable fuel proxy percentage for purposes of this proceeding. Duke reviewed and accepted the results of the analysis performed by the Public Staff, and no other party opposed the Public Staff's recommendation.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use the 50% fuel percentage as the basis for determining the proxy fuel costs for purchases from power marketers and other suppliers that do not provide actual fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-17

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness Hager and the affidavits and testimony of Public Staff witnesses Peedin 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 expenses of $1,318,414,000 and a base fuel factor of 1.6770¢/kWh, excluding gross receipts tax (as set forth on Hager Exhibit 1, Schedule 2(c)), are reasonable and appropriate for use in this proceeding. This approved base fuel factor is 0.5738¢/kWh higher than the base fuel factor of 1.1032¢/kWh set in the Company's last general rate case, Docket No. E-7, Sub 487.

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 Peedin 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 costs and fuel revenues during the test period. These procedures included a 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 utilized by the Public Staff included review of certain specific types of expenditures impacting the Company's test year fuel 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 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 the source documentation associated with 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.

Witness Peedin testified that she made two adjustments that reduced the Company's test year system fuel expenses. First, she made an adjustment to apply the 50% fuel percentage as discussed above to Duke's purchases from power marketers and other suppliers who do not provide actual fuel costs. Second, witness Peedin recommended an adjustment to reduce North Carolina retail test year fuel expense for the portion of the settlement with Norfolk Southern that was not reflected in test year expenses. The Company applied the settlement payment from Norfolk Southern as a reduction to coal inventory as required by the Uniform System of Accounts. Because it takes several months for coal in inventory to be burned and reflected as actual fuel cost, the entire settlement amount did not flow through test year fuel expense. The Public Staff prefers that the entire settlement amount flow through to fuel expense during this test period.

In her supplemental testimony, Duke witness Hager presented Revised Hager Exhibit 6 setting forth the Company's revised recommended EMF increment. Witness Hager testified that she had reflected witness Peedin's recommended adjustments to test year fuel expense in this exhibit. In addition, witness Hager proposed that an adjustment be made to apply the 50% fuel percentage to purchases of power the Company used to supply intersystem sales. The total over-recovery set forth on Revised Hager Exhibit 6, page 1 of 2 is $3,731,000. Witness Peedin testified that the Public Staff accepted the Company's adjustment and calculation of the total over-recovery. Witness Hager also noted that the deferred tax decrement rider approved by the Commission in Docket No. E-7, Sub 780 for a one year period was not applied to the fuel factor when computing the over-recovery. The rider expires on June 30, 2006. Based upon the evidence in the record, the agreement of the Company and the Public Staff, and the absence of any evidence to the contrary, the Commission concludes that Duke's reasonable North Carolina retail test period jurisdictional fuel expense over-collection is $3,731,000.

Hager Exhibit 5 and Hager Revised Exhibit 6 set forth 54,338,729 MWh as the level of test year adjusted North Carolina retail sales to be used to calculate the EMF increment rider. No party disagreed with this level of MWh sales, and the Commission finds it reasonable.

Duke witness Hager calculated the EMF decrement by dividing the $3,731,000 over-recovered fuel expense by the adjusted North Carolina jurisdictional sales of 54,338,729 MWh to arrive at an EMF decrement of 0.0069¢/kWh, excluding gross receipts tax. She likewise divided the associated interest of $560,000 by the adjusted North Carolina jurisdictional sales of 54,338,729 MWh, producing an EMF interest decrement of 0.0010¢/kWh. Public Staff witness Peedin recommended the same EMF decrement and EMF interest decrements. The Commission concludes that an EMF decrement of 0.0069¢/kWh, excluding gross receipts tax and an EMF interest decrement of 0.0010¢/kWh, are reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in a net fuel factor of 1.6691¢/kWh, excluding gross receipts tax, consisting of a prospective fuel factor of 1.6770¢/kWh and EMF and EMF interest decrements of 0.0069¢/kWh and 0.0010¢/kWh, respectively.

Two other rate changes, which have already been ordered in separate proceedings, should be mentioned here. First, in Duke's 2005 fuel charge adjustment proceeding in Docket No. E-7, Sub 780, the Commission's June 15, 2005 Order approved a rate decrement related to excess deferred income taxes and provided for it to remain in effect for service rendered through June 30, 2006. Expiration of this deferred tax decrement results in an increase of 0.2041 cents per kWh (including North Carolina gross receipts tax). Second, in the recent merger proceedings in Docket No. E-7, Sub 795, the Commission approved a one-year rate decrement in the amount of $117,517,000 in order to share with retail customers some of the cost savings associated with the merger of Duke Energy Corporation and Cinergy Corporation, and the Commission provided for this merger savings decrement to be implemented in conjunction with the 2006 fuel charge adjustment proceedings. On May 30, 2006, the Commission issued an Order in Docket No. E-7, Sub 795, approving a one-year merger savings decrement of 0.2182 cents per kWh (including North Carolina gross receipts tax), effective for service rendered on and after July 1, 2006. Both of these rate changes should be included in the public notice given in conjunction with this docket.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after July 1, 2006, Duke shall adjust the base fuel cost approved in Docket No. E-7, Sub 487, in its North Carolina retail rates by an amount equal to a 0.5738¢/kWh increase (excluding gross receipts tax), and further that Duke shall adjust the resultant approved fuel cost by decrements of 0.0069¢/kWh and 0.0010¢/kWh (excluding gross receipts tax) for the EMF and EMF interest decrements, respectively. The EMF decrement and EMF interest decrement are to remain in effect for service rendered through June 30, 2007.

2. That Duke 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.

3. That Duke 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 27th day of June, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr061906.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 805
DOCKET NO. E-7, SUB 795

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Power, a Division of Duke	)	NOTICE TO CUSTOMERS
Energy Corporation, Pursuant to G.S. 62-133.2	)	OF CHANGE IN RATES
and NCUC Rule R8-55 Relating to Fuel Charge	)	
Adjustments for Electric Utilities	)	

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order in Docket No. E-7, Sub 805, on June 27, 2006, after public hearings, approving a fuel charge net rate increase of 0.1986 cents per kWh (including North Carolina gross receipts tax), or approximately $107,917,000 on an annual basis, in the rates and charges paid by the retail customers of Duke in North Carolina, effective for service rendered on and after July 1, 2006. The rate increase was ordered by the Commission after review of Duke's fuel expense during the 12-month period ended December 31, 2005, and represents actual changes experienced by the Company with respect to its reasonable cost of fuel and the fuel component of purchased power during the test period.

Additionally, the expiration on the same date of the decrement related to excess deferred income taxes approved in Docket No. E-7, Sub 780, results in a further increase of 0.2041 cents per kWh (including North Carolina gross receipts tax).

Finally, on May 30, 2006, the Commission issued an Order in Docket No. E-7, Sub 795, approving a one-year rate decrement of 0.2182 cents per kWh (including North Carolina gross receipts tax), effective for service rendered on and after July 1, 2006, related to cost savings associated with the merger of Duke Energy Corporation and Cinergy Corporation.

The net change in rates will be an increase of 0.1845 cents per kWh, which will be in effect for service rendered for the period of July 1, 2006 through June 30, 2007. The change in approved rates will result in a monthly net rate increase of approximately $1.85 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of June, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. E-22, SUB 436

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Tuesday, November 7, 2006, beginning at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner James Y. Kerr, II, Presiding; and Commissioners Sam J. Ervin, IV, and William T. Culpepper, III

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, 225 Hillsborough Place, Suite 480, Raleigh, North Carolina 27603

James C. Dimitri, McGuire Woods, LLP, 901 East Cary Street, Richmond, Virginia 23219

For 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

Damon E. Xenopoulos, Brickfield, Burchette, Ritts & Stone, 1025 Thomas Jefferson Street, NW, Washington, DC 20007

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, P.O. Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: North Carolina General Statute § 62-133.2 requires the North Carolina Utilities Commission to hold a hearing for each electric utility engaged in the generation and production of electric power by fossil or nuclear fuels 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 Dominion North Carolina Power (Dominion 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 19, 2005 in Docket No. E-22, Sub 428.

On September 8, 2006, Dominion NC Power filed the direct testimony and exhibits of Wesley S. Gregory, Anne M. Tracy, Jack E. Streightiff and Alan L. Meekins pursuant to G.S. § 62-133.2 and Commission Rule R8-55 relating to fuel charge adjustments for electric utilities. The Company also filed information and workpapers required by Commission Rule R8-55(d).

The Carolina Group for Fair Utility Rates (CIGFUR I) filed a petition to intervene on September 11, 2006, which was allowed by Commission Order issued September 14, 2006.

Nucor Steel–Hertford (Nucor), a division of Nucor Corporation, filed a petition to intervene on September 13, 2006, which was allowed by Commission Order issued September 15, 2006.

On September 14, 2006, the Commission issued its Order Scheduling Hearing and Requiring Public Notice. On September 15, 2006, the Commission issued its Order Rescheduling Hearing and Requiring Publication of Revised Notice.

The Attorney General filed a notice of intervention on September 26, 2006.

On October 16, 2006, the Company filed the revised direct testimony and exhibits of Alan L. Meekins.

On October 23, 2006, the Public Staff filed the testimony and exhibits of Darlene P. Peedin, Staff Accountant, and the testimony of Thomas S. Lam, Electric Engineer. On October 31, 2006, the Public Staff filed the revised testimony and exhibits of Ms. Peedin and the revised testimony of Mr. Lam.

On October 23, 2006, Nucor filed the testimony and exhibits of J. Bertram Soloman and Dr. Matthew J. Morey.

On October 26, 2005, the Company filed its Affidavits of Publication.

On November 3, 2006, the Company filed the rebuttal testimony of Jack E. Streightiff, Anne M. Tracy, Andrew J. Evans, Karla J. Haislip and Alan L. Meekins. On November 6, 2006, Dominion NC Power filed Appendix A of Karla J. Haislip's testimony.

At the hearing, the prefiled direct and rebuttal testimony and exhibits of the Company's witnesses, the prefiled revised testimony and exhibits of Public Staff witnesses, and the testimony and exhibits of Nucor's witnesses were admitted into evidence. No public witnesses appeared at the hearing.

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

FINDINGS OF FACT

1. Dominion 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. Dominion NC Power is lawfully before this Commission pursuant to G.S. § 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2006.

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 80,272,456 MWh.

5. The test period per book system generation is 84,610,882 MWh, which includes various generation as follows:

Generation Type	MWh
Coal	33,050,623
Combustion Turbine	3,636,807
Heavy Oil	2,215,509
Nuclear	26,033,795
Hydro	2,577,329
Pumped Storage (Pumping)	(2,778,276)
Power Transactions	
NUG	11,015,103
Other	9,886,973
Sales for Resale	(1,026,981)

6. The nuclear capacity factor appropriate for use in this proceeding is 91.67%, which is the estimated nuclear capacity factor for the twelve months ending December 31, 2007.

7. The adjusted test period system sales for use in this proceeding are 80,464,487 MWh.

8. The adjusted test period system generation for use in this proceeding is 84,817,849 MWh, which is categorized as follows:

Generation Type	MWh
Coal	33,264,124
Combustion Turbine	3,660,300
Heavy Oil	2,229,851
Nuclear	25,854,361
Hydro	2,577,329
Pumped Storage (Pumping)	(2,778,276)
Power Transactions	
NUG	11,086,296
Other	9,950,845
Sales for Resale	(1,026,981)

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

A. $23.47/MWh for coal;
B. $4.25/MWh for nuclear;
C. $82.93/MWh for heavy oil;
D. $64.35/MWh for internal combustion turbine fuel;
E. $40.79/MWh for the fuel price of other power transactions; and,
F. A zero fuel price for hydro and pumped storage.

10. The adjusted test period system fuel expense for use in this proceeding is $1,735,350,975.

11. The proper fuel factor for this proceeding is 2.157¢/kWh, excluding gross receipts tax, or 2.229¢/kWh, including gross receipts tax.

12. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 50% of the energy portion of the purchase price is reasonable for use in this proceeding.

13. The adjustment recommended by the Public Staff reducing the Company's test year North Carolina retail fuel costs by $756,336 of Financial Transmission Rights (FTR) revenue, in order to offset any congestion charges in the fuel component of the Company's net purchased power expense, is necessary to bring the Company's test year fuel costs into compliance with Ordering Paragraph 1, Condition 1(e), as well as Ordering Paragraph 1, Condition 2, of the Commission's Order Approving Transfer Subject to Conditions issued on April 19, 2005, in Docket No. E-22, Sub 418 (PJM Order), and thus is reasonable and appropriate for purposes of this proceeding.

14. The results of Dominion NC Power's study to determine compliance with Ordering Paragraph 1(e) of the PJM Order (hereinafter referred to as the PJM Study) cannot be relied upon and

no explicit or implicit approval or acceptance of Dominion NC Power's methodology should be assumed. The Company should continue to work with the Public Staff and other interested intervenors on the study methodology and file a new study as ordered herein. To the extent the Public Staff or other interested intervenors disagree with the Company's proposed methodology, they may file their own methodology and its results in testimony in the next fuel adjustment proceeding.

15. The appropriate North Carolina test period jurisdictional fuel expense undercollection is $14,084,244. The adjusted North Carolina jurisdictional test year sales are 4,212,758MWh.

16. The appropriate Experience Modification Factor (EMF) for this proceeding is an increment of 0.334¢/kWh, excluding gross receipts tax, or 0.345¢/kWh, including gross receipts tax.

17. The final net fuel factor to be billed to Dominion NC Power's North Carolina retail customers during the 2007 fuel clause billing period is 2.491¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 2.157¢/kWh and the EMF increment of 0.334¢/kWh, or 2.574¢/kWh, including gross receipts tax, consisting of the prospective fuel factor of 2.229¢/kWh and the EMF increment of 0.345¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

General Statute § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for Dominion NC Power. The Company's filing was based on the 12 months ended June 30, 2006.

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 December 30, 2003. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

In pre-filed testimony, Nucor witness Solomon questioned the reasonableness of certain coal purchasing decisions of the Company and recommended that the Commission disallow at least $4.35 million of North Carolina jurisdictional test year fuel costs unless the Company provided adequate support to justify those purchases. However, in response to questions from the Commission during the hearing, witness Solomon testified that he was no longer advancing his disallowance recommendation after his review of the rebuttal testimony of the Company.

No other party offered testimony contesting the Company's fuel procurement and power purchasing practices.

In its brief, Nucor recommended that the Commission should continue this proceeding or initiate a separate proceeding pursuant to G.S. 62-37 to examine the impact of the Company's failure to build or acquire baseload generation over the last several years on its fuel costs. Nucor further recommended that the fuel charge allowed to go into effect in this proceeding should be subject to refund, pending the results of such a proceeding. Nucor stated that such a proceeding is necessary because the annual fuel charge adjustment proceeding, given its compressed schedule, has been too abbreviated to make such an examination. The Commission will not continue this proceeding or initiate a new proceeding pursuant to G.S. 62-37 at this time to address the concerns expressed by Nucor. This ruling is without prejudice to any right of Nucor to raise such concerns in the IRP process or a complaint proceeding.

In its brief, the Attorney General stated that it does not disagree that the Company has carried its burden of proof as to the reasonableness and prudence of the fuel costs incurred by the Company. However, the Attorney General believes that the Company has failed to show its recovery of its fuel costs would hold North Carolina customers harmless from the effects of its participation in PJM. More specifically, the Attorney General argued that the Company has not properly adjusted its fuel costs to account for the substantial increase in purchased power, at significantly higher fuel costs, which resulted from its membership in PJM. According to the Attorney General, if the Company had generated an additional 2,427,828 MWh with its own generating plants, rather than purchasing this power due to its membership in PJM, the Attorney General calculated that North Carolina retail customers would have received the benefit of $1,715,959 in lower fuel costs. Therefore, the Attorney General recommended that the Commission should consider reducing the Company's fuel costs by $1,715,959 in order to hold customers harmless from the fuel cost increase resulting from Dominion NC Power's increase in purchased power. After careful review of the record and the Attorney General's position on this issue, the Commission questions certain of the numerous and important assumptions underlying the Attorney General's position and calculations. For example, the Attorney General assumes that the Company's generating units could and should have purchased the additional purchased power at $20.23 per MWh, which is the average fuel cost of the Company's coal, nuclear, oil and natural gas generating units. The Commission notes that Table 2 in the Attorney General's brief shows that only nuclear generation had an average system fuel cost less than $20.23 in the test year. The Commission is unable to conclude that these assumptions are valid and cannot, for that reason, accept the Attorney General's proposed adjustment.

Based on the fuel procurement practices report and the absence of an appropriate basis for reaching a contrary conclusion, the Commission concludes that the Company's fuel procurement and power purchasing practices were reasonable and prudent during the test year.

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 Tracy and Streightiff and the testimony of Public Staff witness Lam.

Witness Streightiff testified that the test period per book system sales were 80,272,456 MWh and test period per book system generation was 84,610,882 MWh. The test period per book system generation is categorized as follows:

Generation Type	MWH
Coal	33,050,623
Combustion Turbine	3,636,807
Heavy Oil	2,215,509
Nuclear	26,033,795
Hydro	2,577,329
Pumped Storage (Pumping)	(2,778,276)
Power Transactions	
NUG	11,015,103
Other	9,886,973
Sales for Resale	(1,026,981)
Total Generation	84,610,882

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 Tracy testified that the Company achieved a system nuclear capacity factor of 92.43% for the July 1, 2005, to June 30, 2006, test period. Public Staff witness Lam stated that the most recent (2001-2005) NERC five-year average nuclear capacity factor for pressurized water reactor units is 86.63%. Witness Tracy normalized the system nuclear capacity factor to a level of 91.67%, which is the estimated nuclear capacity factor for the twelve months ending December 31, 2007. Witness Lam agreed that the nuclear capacity factor of 92.43% as achieved by the Company should be normalized as proposed. No other party offered or elicited testimony on the normalized nuclear capacity factor.

The Commission concludes that the July 1, 2005, to June 30, 2006, test period levels of sales and generation are reasonable and appropriate for use in this proceeding, as is the 91.67% 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 Streightiff.

Witness Steightiff testified that the Company's system sales for the twelve months ended June 30, 2006, were adjusted for weather normalization, customer growth and increased usage in accordance with Commission Rule R8-55(d)(2). Witness Streightiff adjusted total Company sales by 192,031 MWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 395,937 MWh, 183,690 MWh and (269,873) MWh, respectively, and an adjustment of (117,723) 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 20, 2006, were 80,464,487 MWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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

Company witness Streightiff presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2006, due to weather normalization, customer growth, and increased usage of 206,967 MWh, to arrive at witness Tracy's adjusted generation level of 84,817,849 MWh. Public Staff witness Lam reviewed and accepted witness Streightiff's adjustment and also accepted witness Tracy's adjusted generation level of 84,817,849 MWh, which includes generation from various sources as follows:

Generation Type	MWh
Coal	33,264,124
Combustion Turbine	3,660,300
Heavy Oil	2,229,851
Nuclear	25,854,361
Hydro	2,577,329
Pumped Storage (Pumping)	(2,778,276)
Power Transactions	
NUG	11,086,296
Other	9,950,845
Sales for Resale	(1,026,981)

The Commission concludes that it is reasonable and appropriate to use 84,817,849 MWh in this proceeding as the amount of adjusted test period system generation.

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

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

Company Witness Tracy testified that the Company's proposed fuel factor was based on June 2006 fuel prices as follows: (1) coal price of $23.47/MWH; (2) nuclear fuel price of $4.25/MWh; (3) heavy oil price of $126.92/MWh; (4) internal combustion turbine price of $64.35/MWh; (5) other power transactions price of $40.79/ MWh; and (6) hydro and pumped storage at a zero price.

Public Staff witness Lam testified that, based upon his examination, the heavy oil generation price proposed by the Company required adjustment. Mr. Lam stated that the last month of the test period to price fuel for the prospective fuel factor has been used in many of past fuel adjustment cases because the price of fuels has been consistent through the test year. However, in this docket, the price of heavy oil had been in the low to mid $80/MWh price range for all of 2006 except for the $126.92/MWh price for June 2006. As a result, Mr. Lam recommended that the August 2006 rate of $82.93/MWh be used in this fuel adjustment proceeding. Mr. Lam also testified that the replacement of the June 2006 rate of $126.92/MWh with the August 2006 rate of $82.93/MWh reduces the DNCP-filed fuel factor expense by $98,091,145. Witness Lam further testified that the use of the Public Staff's adjusted fuel factor expense of $1,735,350,975 results in a reduction of the DNCP fuel factor from 2.279 ¢/kWh to the Public Staff's recommended fuel factor of 2.157¢/kWh.

The Company did not present evidence to oppose the adjustment made by Mr. Lam and adopted this adjustment in its proposed order. Therefore, in the absence of any evidence to the contrary, the Commission concludes that the fuel prices recommended by Company witness Tracy and adjusted by Public Staff witness Lam are reasonable and appropriate for use in this proceeding.

Company witness Tracy testified that she calculated the level of normalized fuel expenses by multiplying the normalized generation amounts for the Company's generating units by actual June 2006 fuel prices. The level of test period normalized fuel expense resulting from this calculation was $1,833,442,138. The level of test year normalized fuel expense calculated by the Public Staff is $1,735,350,975, which uses the actual June 2006 fuel prices for the generation except for the replacement of the June 2006 heavy oil fuel price of $126.92/MWh with the August 2006 heavy oil fuel price of $82.93/MWh. The Company did not oppose this level of test year normalized fuel expense.

Public Staff witness Lam calculated a proposed fuel factor for the 12 months ended December 31, 2007, by dividing the normalized fuel expense of $1,735,350,975 by the adjusted level of test year system MWh sales (80,464,487 MWh). This calculation results in a proposed fuel factor of 2.157¢/kWh (excluding gross receipts tax) and 2.229¢/kWh (including gross receipts tax). When this fuel factor is reduced by 1.647¢/kWh, the base fuel component approved in the Company's most recent general rate case, the resulting fuel cost rider (Rider A) is 0.510¢/kWh (excluding gross receipts tax) and 0.527¢/kWh (including gross receipts tax). The Company did not oppose witness Lam's calculation.

The Commission concludes that adjusted fuel test period expenses of $1,735,350,975 and the fuel cost rider (Rider A) increment of 0.510¢/kWh, excluding gross receipts tax, or a 0.527¢/kWh increment, including gross receipts tax, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is contained in the testimony of Public Staff witness Peedin. Ms. Peedin testified that, during the test year, Dominion NC Power purchased power from suppliers that did not provide it with the actual fuel costs associated with those purchases. She stated that a similar situation has occurred in each of the fuel proceedings for Duke Energy Carolinas, LLC (Duke), Progress Energy Carolinas, Inc. (PEC), and Dominion NC Power since 1996.

For purposes of determining Dominion NC Power's EMF in this proceeding, Ms. Peedin recommended that the Commission adopt a percentage of 50% to be applied to purchases from power marketers and to purchases from other sellers who do not provide Dominion NC Power with actual fuel costs. To determine this percentage, the Public Staff performed a review of the fuel component of off-system sales made by Duke, PEC, and Dominion NC Power, which are set forth in each of the utilities' Monthly Fuel Reports, for the twelve months ended December 31, 2005. Ms. Peedin indicated that this analysis is similar to that performed by the Public Staff for purposes of implementing both the Marketer Stipulation entered into in 1997 covering these types of purchases (applicable to the 1997 and 1998 fuel proceedings) and a subsequent Marketer Stipulation entered into in 1999 (applicable to the 1999, 2000, and 2001 fuel cost proceedings). The methodology used for both of the above mentioned Marketer Stipulations has been accepted by this Commission as reasonable in each fuel case since the beginning of 1997, including those held in 2002, 2003, 2004, and again in 2005. The methodology has also been accepted by this Commission as reasonable in the 2006 Duke and PEC fuel proceedings.

As part of the current review, the Public Staff analyzed the off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 45.33% to 57.67%, as set forth in Peedin Exhibit II. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel ratio should be 50%.

General Statute § 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's 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."

In her testimony, Public Staff witness Peedin stated 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. She stated that because the sales made by marketers and other supplies 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, in the opinion of the Public Staff, it is reasonably reliable. Finally, Ms. Peedin stated that the Public Staff is unaware of any alternative information currently available concerning the fuel cost component of marketers' sales made to utilities. Therefore, according to Ms. Peedin, the methodology used in past proceedings and in the analysis for this proceeding meets the criteria set forth in the 1996 Duke Order. No other party offered evidence contrary to the Public Staff's position.

The Commission concludes, as it has in past dockets, that the methodology underlying the 1997 and 1999 Marketer Stipulations, i.e., 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 costs, is reasonable and satisfies the requirements set forth in the 1996 Duke fuel case order for purposes of this proceeding. First, the results of applying the methodology are acceptable under G.S. § 62-133.2. As Public Staff witness Peedin stated, 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 therefore finds it reasonable to assume for purposes of this proceeding that the fuel-to-energy percentage exhibited by the utilities' sales is similar to the percentage inherent in the sales made to Dominion NC Power from the same types of generating resources. Second, the Commission concludes that the information used by the parties to derive the fuel ratio is reasonably reliable. According to the testimony of Ms. Peedin, the 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. Therefore, the Commission concludes that the methodology underlying the 1997 and 1999 Marketer Stipulations used in prior cases meets the criteria set forth in the 1996 Duke fuel case order and is reasonable for purposes of this proceeding as the method of determining the proxy fuel cost.

Given the fact that the Commission has concluded that the methodology underlying the 1997 and 1999 Marketer 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 the most recent review, the Public Staff's analyses of off-system sales information resulted in fuel percentages ranging from 45.33% to 57.67% and, based on these analyses, the Public Staff recommended that 50% be used as an appropriate and reasonable fuel percentage for purposes of this proceeding.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use the 50% fuel ratio as the basis for determining the proxy fuel costs for purchases from power marketers and other suppliers that do not provide actual fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Public Staff witness Peedin, the rebuttal testimony of Company witness Evans in this proceeding, and Mr. Evans' rebuttal testimony in Docket No. E-22, Sub 418, the latter of which the Commission takes judicial notice, as well as in the Commission's final orders in Docket No. E-22, Subs 380, 412, and 418, all of which the Commission judicially notices.

Public Staff witness Peedin testified that she recommended an adjustment, in the amount of $756,336 (on a North Carolina retail basis), to reduce the fuel component of purchased power expense by a portion of the Company's Financial Transmission Rights (FTR) revenues recorded during the period May 2005 through June 2006. She indicated that this adjustment was intended to offset any congestion charges that may be included in the Company's net power purchases from PJM Interconnection, L.L.C. (PJM), during that period. She stated that, although the Company had removed congestion costs from fuel expenses associated with the Company's generation, the net kWh the Company purchased from the PJM day-ahead and real-time markets (the kWh in excess of the Company's system generation) may also include congestion charges. Because the specific amount of those congestion charges is not currently quantifiable, Ms. Peedin allocated a proportionate amount of FTR revenue to the fuel component of purchased power expense to offset them.

In support of her adjustment, Ms. Peedin noted that Condition 1, as set forth in Ordering Paragraph 1 of the Commission's PJM Order, requires that the Company's North Carolina retail ratepayers be "held harmless from all direct and indirect effects and costs ... arising from its integration with PJM ...," and includes the following condition specifically related to the Company's fuel rates:

> (1)e. Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2[.]

Condition 2 of Ordering Paragraph 1 requires the following of the Company and PJM:

> (2) That Dominion and PJM shall, consistent with, and to the extent not altered by, the above additional regulatory conditions and this Order, comply with the

> terms of the Joint Offer of Settlement filed [by the Company and PJM] December 16, 2004[.]

Ms. Peedin further noted that as part of the Joint Offer of Settlement (JOS) referenced in Condition 2, the Company agreed that, in any fuel factor in effect through December 31, 2014, it would "credit a portion of its FTR revenues to the cost of PJM Purchases prior to determining the purchased energy expense that the Company flows through the fuel clause." The JOS defined "PJM Purchases" as "purchases from the PJM market in excess of the output of the Company's resources." In testimony prefiled with the Commission in Sub 418 in support of the JOS, Company witness Evans stated that the proposal to credit FTR revenues to the cost of PJM Purchases would provide ratepayers with a benefit that they did not receive prior to integration "by crediting a portion of the Company's hourly FTR value to the fuel clause to offset congestion costs that may be embedded in the cost of PJM purchases."

Ms. Peedin testified that the Public Staff believes that the requirement of the Commission's PJM Order that "any congestion charges ... resulting from Dominion joining PJM" be offset in the fuel rate by FTRs, ARRs, or other revenues, coupled with the requirement that the Company comply with all consistent and non-altered terms of the JOS, makes it reasonable for purposes of this proceeding to make the adjustment to credit FTR revenues to purchased power costs as described in the JOS. She stated that, based on the Public Staff's interpretation of the language of Condition 1(e), she could not reasonably conclude that the FTR credit process as set forth in the JOS had been superseded. The Public Staff believes that the language of the condition refers to "congestion charges" and "other fuel-related costs" as separate categories of cost, and thus requires the removal of both.

Ms. Peedin stated that she had calculated the FTR credit allocation using the method set forth on Maness Exhibit I, Schedule 1, attached to the prefiled testimony of Public Staff witness Michael C. Maness in Docket No. E-22, Sub 418, except that, due to limited time and the absence of readily available information, she had used monthly amounts rather than hourly ones. She indicated that, except for that difference, the method she used was consistent with the method set forth by the Company in the JOS.

During cross-examination, Ms. Peedin was asked if she thought it was fair for the Company to receive less than 50% of purchased energy costs in the fuel clause due to her recommendation regarding the FTR credit, while the other utilities were receiving at least 50%. Ms. Peedin responded that she did not believe that the Company was receiving less than 50%. She stated that the Company had proposed this adjustment in the Sub 418 proceeding as a benefit to its customers and that the Public Staff believes that the Commission had accepted that proposal and also implemented extra safeguards for the customers. She pointed out that the other utilities, unlike the Company, are not integrated with a Regional Transmission Organization (RTO). Ms. Peedin was also asked if the fact that the Company is currently under a rate freeze causes it not to be able to recover in non-fuel rates the 50% or more of purchased power costs it is not able to recover through the fuel clause. Ms. Peedin responded that the Company has recently been involved in a general rate case (Docket No. E-22, Sub 412), and that the Public Staff presumes that its non-fuel costs are being recovered.

Company witness Evans testified that he did not agree with Ms. Peedin's recommended adjustment, both because the Commission's PJM Order did not support it and because it would "improperly deny the Company recovery of its fuel costs." Mr. Evans agreed that, as part of the

Sub 418 JOS, the Company had proposed a credit of FTR revenues to fuel costs to offset congestion charges possibly embedded in the costs of energy purchases from PJM, but asserted that the Commission adopted a much broader and more comprehensive approach in the PJM Order to protect the ratepayers from congestion and fuel-related costs resulting from the Company joining PJM. According to Mr. Evans, the language of Condition 1(e) of the PJM Order requires the Company to simply hold the ratepayers harmless from congestion and fuel-related costs resulting from integration with PJM and that adopting Ms. Peedin's adjustment "would result in windfall benefits to customers." Mr. Evans stated that, in this fuel clause proceeding, the Company had more than held the ratepayers harmless by not including any congestion associated with Company generation and by demonstrating that integration with PJM had actually resulted in lower fuel costs than would have been incurred had the Company not joined PJM.

Mr. Evans testified that, for purposes of Condition 1(e) of the PJM Order, the Commission had defined the term "congestion charges" in the Evidence and Conclusions for Findings of Fact Nos. 13-14 of that Order, wherein the Commission stated, "[l]astly, Condition 1(e) protects Dominion's North Carolina retail ratepayers from congestion costs related to that portion of its load served by Dominion's own generation." According to Mr. Evans, this language indicates that the Commission intended, by way of Condition 1(e), to protect ratepayers from congestion costs associated with Dominion-owned generation, but not from congestion charges embedded in the net purchases made from PJM (those kWh needed to serve the Company's load over and above its system generation). Mr. Evans noted that any congestion charge embedded in the cost of net purchases is not in itself relevant to the Company's decision whether to purchase power from PJM in any given hour because the Company makes its purchase decisions on the basis of the total cost of such purchases, not their individual components. Mr. Evans also noted that, prior to integration with PJM, the Company paid any congestion charges embedded in the price of any purchases it made from PJM, and that those charges had been included in the fuel clause. Mr. Evans stated that "[t]he Commission's Final Order [in Sub 418] required global protection from congestion and fuel related costs resulting from the Company's integration into PJM," and not "the specific FTR adjustment offered in the Joint Offer of Settlement ...."

Mr. Evans further testified that the language of Ordering Paragraph 1, Condition 2 of the PJM Order further supports his assertion that the limited fuel clause protection offered by the Company in the JOS was superseded by the broad language of Condition 1(e). Specifically, Mr. Evans stated that the fact that Condition 2 preserved the protections in the JOS only to "the extent not altered by" the regulatory conditions set forth in the PJM Order indicates that the Commission knew that its broad ratepayer protection with regard to the fuel clause altered, and therefore superseded, the limited protection in the JOS. Furthermore, Mr. Evans testified that the Commission's statements in the PJM Order that "modifications are required to a few of" the conditions set forth in the JOS and that the modified conditions "are made explicit Regulatory Conditions to the Commission's approval" indicates that the Commission intended Condition 1(e) to alter and supersede the fuel clause protection in the JOS. Finally, Mr. Evans testified that his position is supported by the fact that Ordering Paragraph 1, Condition 1(d) of the PJM Order explicitly restated certain JOS conditions related to base rates, but Condition 1(e) contained no such restatement of the JOS condition regarding the fuel clause.

Under cross-examination, Mr. Evans pointed out an additional portion of the Commission's PJM Order that he believes supports the Company's position. He indicated that on page 22 of the PJM Order, the Commission stated:

> Purchases from the wholesale market are, and will continue to be, priced at the market price, using the marketer stipulation to determine the percentages recoverable through fuel rates and through base rates. ... These purchases are priced at LMP and are subject to the rate treatment described above for wholesale purchases. The evidence indicates that any purchases from PJM would be treated in exactly the same way as they are today.

After careful consideration, the Commission concludes that the adjustment recommended by Public Staff witness Peedin is necessary to bring the Company's test year fuel costs into compliance with Ordering Paragraph 1, Condition 1(e), as well as Ordering Paragraph 1, Condition 2, of the Commission's PJM Order, and that it does not result in an unfair denial to the Company of its right to recover prudent and reasonable fuel expenses. Specifically, the requirement that the fuel portion of congestion charges resulting from Dominion joining PJM be offset in the fuel clause by FTR or other revenues is independent of and not reliant upon the existence of "other fuel-related costs" related to joining PJM. Put another way, the allocation of FTR revenues to offset "any congestion costs" is required regardless of whether or not the total impact of belonging to PJM in a fuel case test period is a net benefit or a net cost to the Company.

The Company takes the position that the Commission, through its PJM Order, discarded the limited fuel clause protection set forth in the JOS and instead adopted a much broader and more comprehensive approach to protect the ratepayers from the total fuel-related cost resulting from the Company joining PJM. The Company is incorrect in its conclusion, as a thorough examination of the PJM Order reveals. While the Commission expanded the fuel clause protections in order to allow the Company to join PJM, the Commission in no way discarded the specific fuel clause protection set forth in the JOS.

The evidence that the Commission did not discard the fuel clause protection set forth in the JOS can first and most directly be seen in the language of the PJM Order's Ordering Paragraph 1 and in enumerated paragraph 3 of the JOS itself. Ordering Paragraph 1 reads, in relevant part:

> 1. That the Commission will allow Dominion to join PJM as described in its Application and testimony subject to the following conditions:
>
> > (1) That Dominion's North Carolina retail ratepayers shall be held harmless from all direct and indirect effects and costs, either related to operations, quality of service, reliability, or rates, arising from its integration with PJM including, specifically, the following:
> >
> > ...
> >
> > > e. Dominion shall allocate sufficient FTRs, ARRs, or other revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from Dominion's North Carolina retail ratepayers through the operation of G.S. 62-133.2; ...
> >
> > ...
> >
> > (2) That Dominion and PJM shall, consistent with, and to the extent not altered by, the above additional regulatory conditions and this Order,

> comply with the terms of the Joint Offer of Settlement filed December 16, 2004; ...

Enumerated paragraph 3 of the JOS (JOS Paragraph 3) reads as follows:

> 3. The Company agrees that in any fuel factor in effect through December 31, 2014, the Company will credit a portion of its FTR revenues to the costs of PJM Purchases prior to determining the purchased energy expense that the Company flows through the fuel clause. This credit will be determined by multiplying the total hourly value of the Dominion FTRs for native load obligations in PJM-South by the hourly percentage of PJM Purchases to total load MWhs. The remaining purchased energy expense will be multiplied by the marketer percentage to determine the amount of the purchased energy expense allowed through the fuel clause. As used in this paragraph 3, PJM Purchases are defined as purchases from the PJM market in excess of the output of the Company's resources. Attachment A to this Offer of Settlement provides an example calculation of this change to the current fuel clause methodology.

As discussed above, Public Staff witness Peedin testified that the method she used to calculate the FTR credit was consistent with the method set forth by the Company in the JOS, with the exception that monthly, rather than hourly, amounts were used. Further she testified that congestion charges related to net power purchases from PJM should be removed by the most reasonable means available, and that the method set forth in the JOS currently comprises that means. This testimony was not disputed by any party.

In separate briefs filed after the hearing, CIGFUR 1 and Nucor supported the FTR adjustment recommended by the Public Staff. In its brief, the Attorney General stated that PJM's transmission congestion charges are not fuel costs and must be removed from the purchased power fuel costs. The Attorney General contended that the Company should have obtained the actual amounts of congestion charges included in each purchased power transaction from PJM, despite the testimony of Company witness Evans in this proceeding that PJM could not provide the Company with such charges at this time. Given that the Company did not obtain and deduct the actual congestion charges from its purchased power fuel costs, the Attorney General recommended that one approach the Commission should consider is to disallow a portion of the Company's purchased power fuel costs, allowing instead the recovery of purchased power fuel costs equal to the Company's average generation fuel costs. Using this approach, the Attorney General calculated an adjustment for congestion charges equal to $5,321,007. As an alternative, the Attorney General recommended that the Commission should consider crediting all of the Company's jurisdictional FTR revenues, $11,319,174, to purchased power fuel costs, thereby treating FTR revenues as an appropriate proxy for the actual congestion charges.

Based upon its review of the record concerning this issue, the Commission concludes that the calculation of Public Staff witness Peedin is generally consistent with JOS Paragraph 3 and agrees with her assertion that this method currently comprises the most reasonable means by which to determine and remove congestion charges from fuel costs related to net power purchases from PJM. The methods used by the Attorney General are not consistent with JOS Paragraph 3, and further, there is insufficient evidence in this record to support the assumptions underlying the Attorney

General's calculation of the $5,321,007 adjustment for congestion charges, such as the appropriateness of the assumption that the Company's generating units could have supplied the purchased power at an average fuel cost of $20.23 per MWh.

Therefore, the only issue remaining with regard to the adjustment to remove congestion charges related to net power purchases from PJM is whether the language of Condition 1(e) in the PJM Order is inconsistent with or alters JOS Paragraph 3 in a manner that substantively eliminates the obligation to make the adjustment from the regulatory conditions adopted by the Commission. The Commission believes that this determination is the crux of this issue.

The language of Condition 1(e) itself demonstrates that this is not the case. Condition 1(e) requires the Company to offset from the fuel clause "any congestion charges or other fuel related costs resulting from Dominion joining PJM." The wording of that phrase, particularly the use of the words "any" before "congestion charges," "other" before "fuel related costs," and "or" between the two items, indicates that the Commission's intent was to require both (1) the fuel component of "any" congestion charges resulting from Dominion joining PJM, and (2) "any other" fuel costs resulting from Dominion joining PJM be offset in fuel clause expenses by FTR or other revenues. It is not correct to conclude, as the Company does, that the language of Condition 1(e) simply requires protection from the total of congestion and fuel related costs resulting from PJM integration. If the Commission had intended to simply say that the net fuel cost resulting from Dominion joining PJM should be offset, it could have directly stated that in the condition. Instead, the Commission's choice of language isolates congestion as a specific item to be removed, regardless of the presence of any other fuel costs. Thus, Condition 1(e) is both a preservation of the protections offered in JOS Paragraph 3 regarding congestion charges associated with net purchases and an expansion of that protection by the addition of congestion costs related to the Company's own generation and "other fuel related costs." Even if it can be argued that Condition 1(e) is, as a matter of form, a replacement for, and thus an alteration of, JOS Paragraph 3, Condition 1(e) preserves the JOS Paragraph 3 requirement that the congestion charges associated with net purchases from PJM be offset by FTR revenue.

Mr. Evans has misinterpreted the language of the paragraph he cited in the Evidence and Conclusions for Findings of Fact Nos. 13-14 of the PJM Order, wherein the Commission stated, "[l]astly, Condition (1)e protects Dominion's North Carolina retail ratepayers from congestion costs related to that portion of its load served by Dominion's own generation." This statement is not a "definition," as Mr. Evans puts it, of the <u>only</u> type of congestion charges that Condition 1(e) is intended to address; instead, the statement is intended to specifically identify the type of PJM congestion charges that <u>are not addressed</u> by JOS Paragraph 3 (those related to Company generation), and thus make the expanded protection of Condition 1(e) necessary. Specifically, although Mr. Evans' Sub 418 rebuttal testimony stated that the actual fuel costs for all MWh generated by Company-owned resources would continue to be used to calculate fuel expenses for the North Carolina retail fuel clause (thus excluding PJM congestion charges related to that generation from the fuel clause), the JOS did not directly address that type of congestion charges. Therefore, the first sentence of the paragraph in the PJM Order cited by Mr. Evans simply emphasizes that Condition 1(e) explicitly provides for the exclusion of those Company generation-related PJM congestion charges that had not been explicitly addressed in the JOS.

Furthermore, an examination of the paragraph cited by Mr. Evans in its entirety makes it clear that the Commission's intent was to protect North Carolina retail customers from all PJM congestion charges. The paragraph in its entirety reads as follows:

> Lastly, Condition (1)e protects Dominion's North Carolina retail ratepayers from congestion costs related to that portion of its load served by Dominion's own generation. Dominion's own cost/benefit study indicated that Dominion's participation in PJM is expected to raise fuel costs over the ten-year study period by $5.6 million. CUCA argued that the Commission should, in order to protect ratepayers, order Dominion to allocate additional FTR revenues as a credit against such increased fuel costs. The Commission concludes that the solution proposed by CUCA to address this problem is reasonable and adopts Condition (1)e to require Dominion to allocate sufficient revenues toward its fuel costs to offset any congestion charges or other fuel-related costs resulting from Dominion joining PJM and sought to be recovered from North Carolina retail ratepayers through the fuel clause. The revised JOS proposed to allocate approximately $2.8 million in FTR revenues as a partial offset to the increased fuel costs, leaving ratepayers with an increase totaling $2.8 million over ten years. It is unreasonable to expect ratepayers to bear this cost for the foreseeable future since the purported savings identified in the CRA study benefit ratepayers only by adjusting base rates.

While this paragraph begins with the statement that Condition 1(e) protects the customers from congestion costs associated with the Company's generation (which it certainly does), the paragraph goes on to state that the condition requires the Company to use FTR or other revenues to offset "any congestion charges ... resulting from Dominion joining PJM." There is no reason to conclude that "any congestion charges" means anything less than all congestion charges that may be associated with purchases from PJM. The CUCA proposal discussed in the paragraph was made with specific reference to the Charles River Associates (CRA) cost/benefit study presented by Company witness Robert Stoddard in his rebuttal testimony in the PJM proceeding, which projected that the net fuel cost of joining PJM over the first ten years would be more than the allocation of FTR revenues proposed by the Company in the JOS. The use of the CRA study results by the Commission as a basis for discussing the need for Condition 1(e) was not intended to override the condition's clear language that the customers should be protected from all congestion costs resulting from Dominion's integration with PJM, regardless of the presence or absence of other fuel costs.

Mr. Evans also misinterprets the meaning and intent of the other portion of the PJM Order that he discussed during his cross-examination (the portion he refers to as being on page 22 of the PJM Order). That portion of the PJM Order also is included in the Evidence and Conclusions for Finding of Fact Nos. 13-14, and reads as follows:

> Purchases from the wholesale market are, and will continue to be, priced at the market price, using the marketer stipulation to determine the percentages recoverable through fuel rates and through base rates. ... These purchases are priced at LMP and are subject to the rate treatment described above for wholesale purchases. The evidence indicates that any purchases from PJM would be treated in exactly the same way as they are today.

Mr. Evans appears to contend that via this language, the Commission indicated that it intended for the Company to treat purchases from PJM exactly the same way for fuel clause ratemaking purposes after integration as it did before integration. This interpretation is incorrect and, furthermore, ignores several key factors. First, it must be noted that this portion of the PJM Order is included in the Commission's discussion of Condition 1(b), which generally requires the Company to continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase, not the portion of the Order dealing with the treatment of such costs in fuel clause proceedings. Second, the quoted passage clearly reflects statements and conclusions set forth on pages 19 and 20 of the Company's proposed order in Sub 418, in which the Company also recommended that the JOS be adopted. Thus, in order for the Company to maintain that the quoted Commission statements support the abandonment of the ratepayer protection offered by JOS Paragraph 3, it also must maintain that the Commission's use of language very similar to that used by the Company in its proposed order (wherein it supported the JOS) means something entirely different than it meant when used by the Company. . Third, the Company has ignored the two sentences directly following the end of the quoted language, which state the following:

> Dominion's customers should realize a benefit if these purchases truly replace more expensive Company generation. The Company will not, however, be allowed to use such market purchases to recover excessive costs from North Carolina retail ratepayers through the operation of the fuel adjustment clause mechanism.

By the inclusion of this last sentence, the Commission clearly intended to indicate that the general discussion of the treatment of purchases included in the discussion of Condition 1(b) was not intended to override the specific Condition 1(e) directives regarding the fuel clause treatment of PJM congestion charges and any other applicable fuel-related costs. Thus, the passage quoted by Mr. Evans is irrelevant to the FTR credit adjustment at issue here.

The Commission also desires to make it clear that, contrary to the assertions made by Mr. Evans, the language in the PJM Order regarding the need for modifications to a few of the provisions of the JOS and the presentation of those modified provisions (including Condition 1(e)) as explicit Regulatory Conditions in the Order was not intended to indicate that the provisions of JOS Paragraph 3 were somehow discarded or replaced by Condition 1(e). It is important to note that the language quoted by Mr. Evans in this regard (set forth in the "Extension of Proposed Settlements" section of the Evidence and Conclusions for Findings of Fact Nos. 13-14) was in fact simply referring back to the Commission's previous discussion in that portion of the Order. If the previous sections of the Evidence and Conclusions for Findings of Fact Nos. 13-14 to which the quoted language refers are reviewed, the following is clear: (1) the Commission stated that "certain Regulatory Conditions may be adopted <u>in addition to</u> those proposed by Dominion and PJM in the revised JOS," (2) the Commission referred to "[t]he <u>additional</u> Regulatory Conditions adopted herein," and (3) the Commission stated, "[T]he Application cannot be approved without <u>additional</u> regulatory conditions that will protect Dominion's North Carolina retail ratepayers ...." (Emphasis added) Thus, the entire thrust of the Evidence and Conclusions for Findings of Fact Nos. 13 and 14 is the need to adopt additional protections for ratepayers over and above those offered in the JOS, not on the discarding of the JOS protections. Furthermore, as previously stated, even if it can be argued as a matter of form that Condition 1(e) is a replacement for JOS Paragraph 3, Condition 1(e) effectively preserves and expands, rather than discards, the JOS Paragraph 3 requirement.

Additionally, the Commission desires to make it clear that its restatement of certain JOS provisions in Ordering Paragraph 1, Condition 1(d), was not intended to indicate the abandonment of any JOS provision that had not been restated. In addition to the simple logical fallacy of that assertion, the language of Condition 1(e) preserves the substance of the JOS Paragraph 3 protection, even though it does not quote JOS Paragraph 3 word-for-word. Moreover, the fact that Condition 1(d) incorporates certain unaltered provisions of the JOS, even in the presence of Condition 2, supports the conclusion that Condition 1(e) can incorporate the substantive requirements of JOS Paragraph 3, even in the presence of Condition 2. In other words, the mere existence of Condition 1(e) does not prove that JOS Paragraph 3 has been altered or superseded.

The Commission also disagrees with Mr. Evans' assertion that adoption of the adjustment would "improperly deny the Company recovery of its fuel costs" and "result in windfall benefits to customers." Although the allocation of FTR revenues to the fuel clause as an offset to net purchase-related congestion charges does reduce the Company's fuel rate, it does not improperly deny the Company recovery of its fuel costs. To the contrary, it simply implements the reasonable and appropriate safeguard put in place by the Commission in its PJM Order to protect the Company's North Carolina retail ratepayers from the risks of the Company's integration into PJM. In addition, it is consistent with safeguards that the Commission has historically put in place in connection with mergers and other transfers of ownership and/or control approved pursuant to G.S. § 62-111.

In order to illustrate the incorrectness of the Company's assertion, it is helpful to reiterate the statutory standard followed by the Commission in making its determinations in the PJM proceeding. This standard is set forth as follows in the Evidence and Conclusions for Finding of Fact No. 12 in the PJM Order:

> Pursuant to G.S. 62-111, Dominion must demonstrate that the proposed transfer of control over its transmission and generating assets to PJM would be justified by the public convenience and necessity. This standard requires that the Commission consider all aspects of the proposed transaction. See State ex rel. Utilities Commission v. Village of Pinehurst, 99 N.C. App. 224,393 S.E.2d 111, aff'd, 331 N.C. 278, 415 S.E.2d 199 (1990). In merger and holding company applications under G.S. 62-111, the Commission has consistently examined three aspects of the proposed transaction:
>
> (1) whether sufficient regulatory conditions can be imposed to ensure that the transfer will not adversely impact the utility's rates and services;
>
> (2) whether the utility's retail ratepayers will be protected as much as possible from potential harms, including adverse effects that could result from any loss of the Commission's regulatory authority; and
>
> (3) whether the utility's retail ratepayers will receive sufficient benefits to offset any potential costs, risks and harms.

As the PJM Order states, this statutory standard is the same as has been applied in several, if not all, of the merger applications to come before the Commission in recent years, including the Duke Power-PanEnergy merger (Docket No. E-7, Sub 596), the Carolina Power & Light (CP&L)-North Carolina Natural Gas (NCNG) merger (Docket No. E-2, Sub 740), the Dominion-Consolidated

Natural Gas (CNG) merger (Docket No. E-22, Sub 380), and the CP&L-Florida Progress Corporation (FPC) merger (Docket No. E-2, Sub 760).

After summarizing the terms of the JOS filed by the Company and PJM, the PJM Order sets forth the Commission's conclusion regarding the Company's satisfaction of the requirements of the statute:

> In applying the statutory standard to the evidence presented by the parties in this proceeding, the Commission concludes that Dominion has failed to show that, absent further regulatory conditions in addition to those proposed in the revised JOS, the proposed transfer to PJM will serve the public convenience and necessity as required under G.S. 62-111. Dominion's application to join PJM, absent further regulatory conditions, fails to meet this public convenience and necessity standard for three reasons. First, the transfer would likely adversely impact the utility's rates because the quantifiable costs to Dominion's retail ratepayers exceed the quantifiable benefits. Second, the transfer could result in the loss of a substantial portion of the Commission's regulatory authority, causing harm to Dominion's retail ratepayers. Third, the revised JOS filed by Dominion and PJM does not adequately insulate Dominion's retail ratepayers from these costs and risks.

The Commission then proceeds to discuss in detail the reasons that the application fails to meet the statutory standard in the areas of costs and benefits, regulatory authority, and insulation from costs and risks. With specific regard to the adjustment at issue here, the Order states:

> The conditions proposed by Dominion and PJM in [the] revised JOS do not resolve all of the cost and jurisdictional concerns raised by Dominion's membership in PJM. For example, the proposed conditions to exclude administrative fees, congestion costs and some increases in transmission service charges from Dominion's base rates, as well as to credit a portion of FTR revenues to fuel costs, would all expire on December 31, 2014.

In the Evidence and Conclusions for Findings of Fact Nos. 13-14, as noted previously, the Commission goes on to state that the Company's application could not be approved without additional regulatory conditions; in other words, the application would not meet the statutory standard necessary for approval without those additional conditions. Regarding these additional conditions, the Commission's PJM Order states the following:

> These regulatory conditions are broadly intended to accomplish the following: (1) to hold Dominion's North Carolina retail ratepayers harmless from the potential costs and risks that might result from Dominion's integration into PJM as to (i) base rates, (ii) adjustments in the cost of fuel, and (iii) reliability; (2) to preserve the Commission's existing authority to set the rates, terms, and conditions of retail electric service to Dominion's North Carolina retail ratepayers; and (3) to extend the duration and applicability of the protections proposed by Dominion and PJM in the revised JOS and the Progress Settlement.

Among the additional conditions found necessary are parts of Condition 1(a) and Condition 1(e) (the expanded fuel protections).

From the foregoing, it is clear that the rationale for the imposition of regulatory conditions in Sub 418 was similar to and consistent with the imposition of regulatory conditions in previously approved mergers and transfers of ownership and/or control. More specifically, the imposition of Condition 1(e) and the requirement that the Company continue to comply with JOS Paragraph 3 is similar to the rate cap and rate reduction conditions imposed by the Commission in prior proceedings. For example, in the Duke Power-PanEnergy, CP&L-NCNG, and Dominion-CNG proceedings, the Commission imposed rate caps for periods ranging from four to six years; in the CP&L-FPC proceeding (and in the subsequent Duke Power-Cinergy proceeding), the Commission required rate reductions to be passed on to North Carolina retail ratepayers. A common characteristic of all of these ratepayer benefits was that they did not require compliance with any earnings or other types of tests before they were implemented; they were simply up-front safeguards required by the Commission to ensure that the merger or transfer of ownership and/or control satisfied the public convenience and necessity standard of G.S. § 62-111. The Commission considers the requirement that a credit of FTR or other revenues be applied against the cost of net power purchases from PJM, as set forth in JOS Paragraph 3 and carried forward in Condition 1(e), to be a safeguard similar to the rate cap and rate reduction safeguards put in place in other G.S. § 62-111 proceedings: a rate benefit provided to the customers, without earnings or other types of testing, to ensure that Dominion's North Carolina retail ratepayers are held harmless from the potential costs and risks that might result from Dominion's integration into PJM.

With regard to the Company's cross-examination of Ms. Peedin addressing whether it was fair for her adjustment to be made when it caused the Company to receive less than 50% (the current marketer percentage) of purchased energy costs through the fuel clause, the Commission concludes that the assertion inherent in that cross-examination is without merit. The Commission agrees with Ms. Peedin that the Company will not truly receive less than 50% due to adoption of her recommended adjustment. The calculation of a percentage less than 50% would unreasonably mix two adjustments to purchased energy costs (the marketer adjustment and the FTR credit adjustment) made for two different reasons.

With regard to the Company's implication that it would be unfair to make the FTR credit adjustment during a rate freeze period, when the Company cannot undertake a general rate case to recover any related increase in non-fuel costs, the Commission likewise finds that the Company's assertion is both generally without merit and contrary to the Stipulation entered into by the Company in its most recent general rate case, Docket No. E-22, Sub 412. In general, the fact that a utility is under a rate freeze does not nullify the ratemaking principle that utility costs incurred in the interim period between general rate cases are presumed to be recovered by revenues earned during that period. More specifically, the Stipulation and Agreement entered into by the Company and several intervenors in the Sub 412 general rate case, which was adopted by the Commission and effectively settled the case, contains several provisions that would seem to strongly discourage the Company from even advancing such an assertion. First, via the Stipulation, the Company voluntarily entered into the rate freeze; thus, it is generally difficult to see how the Company could reasonably complain about its effects now. Furthermore, the Rate Change Moratorium section of the Stipulation contains the following specific items that appear to invalidate such claims of unfairness:

A. None of DNCP's North Carolina retail electric rates will be increased or decreased from the levels established pursuant to this Stipulation and Agreement for five years from the Effective Date of those rates (the Rate

> Change Moratorium Period) except (1) as a result of fuel cost adjustment proceedings held pursuant to G.S. 62-133.2 ...
>
> ...
>
> C. The Stipulating Parties agree and recommend that an order accepting this Stipulation and Agreement contain the following provisions:
>
> (1) The rates approved by this order are intended to recover the specific costs incurred by DNCP to provide electric service to its North Carolina retail customers during the Rate Change Moratorium Period and afterwards until changed pursuant to law....

Thus, the Stipulation maintains the Commission's full authority to conduct fuel cost adjustment proceedings such as this one during the rate freeze period (and adjust fuel rates accordingly, without consideration of the freeze on the non-fuel portion of rates), and explicitly sets forth the presumption that the non-fuel costs incurred during the rate freeze period are intended to be recovered by the non-fuel portion of the rates in effect during that period. It is, therefore, erroneous for the Company to claim that adjustments made in fuel cost proceedings during the current rate freeze are unfair simply because there is a rate freeze in effect. More specifically, there is nothing inherent in the FTR credit adjustment that would make it particularly susceptible to such a claim.

Finally, in addition to the above discussion of the Commission's intent in issuing the PJM Order and the reasons why the FTR credit adjustment recommended by the Public Staff is reasonable and fair, there is one common-sense factor that particularly highlights the appropriateness of the adjustment. It is clear that the Company believes that, if its fuel costs were calculated in this proceeding in accordance with its interpretation of the PJM Order, then they would be higher than they would be if they were calculated in accordance with the JOS and Mr. Evans' Sub 418 testimony. (The fuel costs are higher under the Company's interpretation of the PJM Order because that interpretation eliminates the FTR allocation offered in the JOS and Mr. Evan's rebuttal testimony.) This higher cost outcome is not consistent with the Commission's intent when it added conditions to the JOS. The Commission wishes to make it absolutely clear that it did not and does not intend that fuel expenses in any test period determined in accordance with its PJM Order will be greater than fuel expenses would have been if determined solely by the JOS.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding can be found in the Company's Application and in the direct testimony and exhibits of Dominion NC Power witness Meekins, Public Staff witness Lam, and Nucor witness Morey and the rebuttal testimony of Dominion NC Power witness Meekins.

Witness Meekins testified that, in the last fuel clause proceeding, the Company was ordered to prepare a study showing the impact of its integration into PJM on the North Carolina fuel clause. The study compared Dominion NC Power's current total fuel expenses versus that of the hypothetical case of Dominion NC Power operating as a stand alone utility. He filed this PJM Study with his testimony and testified that it showed, for the months of May 2005 through June 2006, that the purchases from PJM were economical as compared to Dominion NC Power running as a stand alone utility outside of the PJM system, and that the fuel factor in the PJM case was slightly lower than in the stand alone case. Witness Meekins testified that no adjustments were required to comply with

Ordering Paragraph 1(e) of the Commission's PJM Order. However, in his rebuttal, Mr. Meekins discussed the problems the Public Staff and Nucor had raised with Dominion NC Power's PJM Study and concluded that "[t]he Public Staff has raised some valid concerns regarding the dispatch of some of our coal units, which we agree with and we have attempted to capture the bulk of those differences in the revised study filed as part of this testimony."

Public Staff witness Lam testified that his investigation of the PJM study found four items that warranted discussion.

The first item was the fact that many coal units in the Stand Alone Case produced less generation than the same units in the PJM Case for the identical month and load served. Mr. Lam testified that this was surprisingly true even for some of the low cost base load units in the Stand Alone Case. Witness Lam testified that "[a] stand alone utility, when faced with limited availability of purchased power, would run its lowest cost coal units as much as the load would allow. The PJM Case, which shows much larger quantities of purchased power being available around the clock, should show these coal units running less, not more." Dominion NC Power acknowledged a mistake was made in the model runs and corrected some of the months, but did not explain the remaining differences to the Public Staff's satisfaction.

The second item involved the pricing for oil, CT and natural gas units in the Stand Alone Case. Many of the units in the Stand Alone Case had higher unit fuel prices and higher generation levels than the same units in the PJM Case for the same months of operations. The Company contended that many of the gas and oil-fired units in the Stand Alone Case ran many of the days when the same units were not dispatched by PJM. In its proposed order, the Public Staff acknowledged that prices can change, but stated that the explanation of the Company does not satisfactorily explain such differences.

The third item involved discrepancies between Dominion NC Power's monthly unit details for coal and nuclear units in Attachment 2 to the PJM Study and the monthly coal and nuclear totals in Attachment 1 to the PJM Study. When added up, the monthly individual unit data on Attachment 2 did not equal the total amounts for the same units shown on Attachment 1. Cross-examination by the Public Staff of Company witness Meekins showed that, in a number of months, Mr. Meekins' revised testimony still showed the nuclear generation in the Stand Alone Case to be zero. Dominion NC Power witness Meekins testified that he corrected the data for only five of the 14 months in the study. In its proposed order, the Public Staff stated that this is not a satisfactory explanation or correction of the differences between Attachment 1 and Attachment 2 for the Stand Alone Case.

The fourth item discussed in Public Staff witness Lam's testimony is the use of too low a percentage of purchased power in the Stand Alone Case when compared to the equivalent months after integration with PJM. According to Mr. Lam, Dominion NC Power made the first calculation of 30% of the PJM purchased power available to the Stand Alone Case from the seven stand alone months (October 2004 through April 2005) compared to the first eight months (May 2005 through December 2005) for the Company in PJM. This early calculation was made to allow an early review of the study methodology, in February 2006, as opposed to waiting until the end of the test period (June 2006), and then first reviewing it in the middle of August 2006. When the remaining six months of the fuel test period (January 2006 through June 2006) were incorporated, the initial 30% purchased power calculation for the Stand Alone Case was not revised, even though the study period had changed greatly. Public Staff witness Lam testified that, when he compared the seven months in the Stand Alone Case to the comparable months in the PJM case, the allocation percentage changed to approximately 35%. He also testified that further investigation might yield an even higher number and that he had calculated the reduction in the costs for the Stand Alone Case to be $100 million if the percentage were increased from 30% to 40%, which would significantly erode the benefit Dominion NC Power shows in its study. According to his testimony, the Company's response to the Public Staff's calculation of 35% was "...that both numbers were in the ballpark". The Company did not agree with the Public Staff hypothetical calculation of 40% and a possible replacement power cost reduction of $100 million.

As a result of this investigation of the PJM study, Public Staff witness Lam recommended that no adjustment to the fuel costs be made for this test period. However, because of the numerous problems with the study, Mr. Lam further recommended that the study process be refined for future test years to ensure that the Commission's condition is satisfied. Witness Lam testified that the Public Staff intends to work with Dominion NC Power and any intervenors who are interested and devise a schedule to continue working on the study methodology and inputs prior to the Company's next fuel clause adjustment proceeding. In response to questions from Commissioners Ervin and Kerr regarding the study, Mr. Lam reiterated that further work needed to be done. Following these responses, counsel for the Company stated that the Company would stipulate for the record that it would continue to work with the Public Staff and with other parties to make sure that the benefits from PJM are understood.

Nucor witness Dr. Morey presented testimony addressing two issues with respect to Dominion NC Power's comparative study of the fuel clause impacts of integration into PJM versus continuing to operate as a stand alone utility. The first issue drew a comparison between the current Dominion NC Power fuel impacts study discussed in witness Meekins testimony and the fuel factor impacts estimated in the study by Charles River Associates submitted on behalf of Dominion NC Power in Docket No. E-22, Sub 418. The second issue involved problems that Dr. Morey believes exist with the current study that render its results unreliable as a basis for determining whether Dominion NC Power's North Carolina retail customers have benefited from its integration into PJM.

With respect to the first issue, Dr. Morey concluded that with the range of possible outcomes from the use of the study method encompassing both benefits and costs from PJM integration, Dominion's NC Power's PJM Study should not be relied upon to make a determination about changes to the fuel cost rider at this time. With respect to the second issue, Dr. Morey stated that the fuel clause benefits in the current study are highly sensitive to the purchased power assumption made in the Stand Alone Case. Dr. Morey testified that a plausible, but conservative, assumed increase in the amount of purchased power each month in the Stand Alone Case, relative to the purchased power in the PJM Case, results in fuel costs in the PJM Case being higher than in the Stand Alone Case. Dr. Morey also listed other shortcomings in the study and concluded that Dominion NC Power had not shown that lower fuel costs are actually attributable to integration into PJM. According to his testimony, the fuel cost savings from the PJM study of the Company is an artifact of the assumption of lower purchases, not the result of a demonstration that a stand alone utility could operate as efficiently as a utility integrated into PJM. He further testified that the fundamental problem with the methodology of the current study is that it does not show that integration itself has produced a change in fuel costs. The assumption of lower economy purchases in the Stand Alone Case for the test year is the basis for the study when it should be the result of a definitive study.

Dr. Morey recommended that the Commission not use the results of the study to make a determination of what adjustment to make to the fuel cost rider in this proceeding because to do so could be interpreted as implicitly approving Dominion NC Power's methodology, which would create the great risk that additional unwarranted costs of Dominion NC Power's joining PJM would be imposed on Dominion NC Power's North Carolina retail customers. Second, he recommended that the Commission reject the methodology of the study as a means of showing what the fuel clause impacts are of Dominion NC Power joining PJM. Finally, he stated that, to clear up the problems with the current study, a new study with a different approach is needed and that the Commission should seek to ensure a credible study is filed in the future.

In its brief, Nucor stated that the informal collaborative process has failed to produce an accurate study. Therefore, Nucor recommends that the Commission should continue this proceeding, and establish a formal process by which the Company, Commission staff, and intervenors can work together to produce an acceptable study method that will accurately show the impact of the Company's integration into PJM on the North Carolina fuel charge. Further, Nucor believes that the fuel charge which is allowed to go into effect in this proceeding should be subject to refund pending the results of a revised and accurate study. Finally in this proceeding, Nucor recommends that once an accurate study is developed, the Company should be required to use that study method during all subsequent proceedings conducted pursuant to G.S. 62-133.2.

The Attorney General's brief stated that the testimony of witnesses Morey, Meekins, and Lam pointed out problems with the PJM study. Therefore, the Attorney General recommended that the Commission should not accept the PJM study or rely upon it as proof that the Company has held its ratepayers harmless from the adverse fuel cost effects of integration into PJM. The Attorney General noted that the Company and the Public Staff have agreed to work together to improve the study for use in future fuel cases.

Based on the evidence, the Commission finds and concludes that no further adjustments to Dominion NC Power's fuel costs should be made in this proceeding, but that the results of the study shall not be relied upon and that nothing in this Order should be interpreted or construed as an explicit or implicit approval, acceptance or endorsement of Dominion NC Power's methodology. A new study is needed and the Commission intends to ensure that a credible study is filed in the future. The Commission further concludes that the Company should continue to work with the Public Staff and other interested intervenors on the study methodology and file a new study on February 15, 2007, incorporating the results of the revised methodology using the first six months of the next test period (July 2006 through December 2006). The Company shall continue to work with the Public Staff and other interested intervenors on the methodology, and file on August 15, 2007, the study results for the entire test period (July 2006 through June 2007). The Company shall then continue to work with the parties on the study methodology until it files its testimony for the next fuel adjustment in September 2007. To the extent the Public Staff or other interested intervenors disagree with the Company's proposed methodology, they may file their own methodology and its results in testimony in the next fuel adjustment proceeding.

At this point in time, the Commission prefers to continue a collaborative process. The Commission strongly encourages the Company and interested parties to make their best efforts to work together to try and reach as much agreement as possible on the appropriate study methodology, underlying assumptions, and data inputs. The Commission expects the Company to respond fully and in a timely manner to requests for information and such requests should be reasonable. Any party that wishes to bring any issue relating to data availability or any other aspect of the study process should feel free to bring that issue to the Commission for resolution.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 & 16

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

Company witness Gregory testified that the Company under-collected its fuel expenses by $17,838,573 during the test year ending June 30, 2006.

Public Staff witness Peedin investigated the Experience Modification Factor (EMF) to determine whether the Company properly determined its fuel costs during the test period. Ms. Peedin's investigation resulted in three adjustments. The first adjustment relates to the marketer stipulation and resulted in decreasing Dominion NC Power's North Carolina retail fuel expense by $3,018,127, as discussed in Evidence and Conclusions for Finding of Fact No. 12. The second adjustment relates to a credit of FTR revenues to purchased power expense and resulted in a reduction to Dominion NC Power's North Carolina retail fuel expense in the amount of $756,336, as discussed in the Evidence and Conclusions for Finding of Fact No. 13. She also adjusted test year fuel costs to include the energy and generation imbalance costs, which resulted in increasing North Carolina retail test year fuel costs by $20,134. The combination of the three adjustments reduced the total test year fuel under-recovery from $17,838,573 to $14,084,244. Based upon the evidence, the Commission finds and concludes that the appropriate North Carolina jurisdictional test year fuel expense under-collection is $14,084,244.

Company witness Streightiff indicated that the appropriate and reasonable level of adjusted North Carolina retail sales for the test year is 4,212,758 MWh. No party disagreed with this level, and the Commission finds it reasonable.

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

The $14,084,244 under-recovered fuel expense can thus be divided by the adjusted North Carolina jurisdictional sales of 4,212,758 MWh to arrive at an EMF increment of 0.334¢/kWh, excluding gross receipts tax, or 0.345¢/kWh including gross receipts tax. The Commission concludes that this EMF increment of 0.334¢/kWh, excluding gross receipts tax, or 0.345¢/kWh, including gross receipts tax, is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is cumulative and is contained in the testimony and exhibits of Company witnesses Gregory and Streightiff and the testimony of Public Staff witnesses Peedin and Lam.

Based upon the above findings, the Commission finds and concludes that the final net fuel factor approved for usage in this proceeding is 2.491¢/kWh, excluding gross receipts tax, and 2.574¢/kwh, including gross receipts tax.

This final net fuel factor is determined as follows:

Normalized System Fuel Expense	\$1,735,350,975
System kWh Sales at Sales Level	80,464,487,281
Test Year North Carolina Retail Fuel Underrecovery	\$14,084,244
North Carolina Retail kWh Sales At Sales Level	4,212,758,202
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 =
1.647¢/kWh x 1.03327 = 1.702¢/kWh

Fuel Cost Rider A (excluding gross receipts tax) =
[(\$1,735,350,975)/ 80,464,487,281]-1.647¢/kWh = \$0.510¢/kWh

Fuel Cost Rider A (including gross receipts tax) =
\$0.510¢/kWh x 1.03327 = \$0.527¢/kWh

Fuel Cost Rider B (excluding gross receipts tax) =
[(\$14,084,244)/4,212,758,202] = \$0.334¢/kWh

Fuel Cost Rider B (including gross receipts tax) =
\$0.334¢/kWh x 1.03327 = \$0.345¢/kWh

	Effective 1/1/2007 (¢/kWh Including Gross Receipts Tax)
Base Fuel Factor	1.702
EMF/Rider B	.345
Fuel Cost Rider A	.527
FINAL FUEL FACTOR	2.574

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2007, Dominion 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 0.510¢/kWh, excluding gross receipts tax, or 0.527¢/kWh, including gross receipts tax;

2. That an EMF Rider increment (Rider B) of 0.334¢/kWh, excluding gross receipts tax, or 0.345¢/kWh, including gross receipts tax, shall be instituted and remain in effect for usage from January 1, 2007, until December 31, 2007;

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

5. That Dominion North Carolina Power shall do the following:

(a) continue to work with the Public Staff and other interested intervenors on the study methodology and file a new study on February 15, 2007, incorporating the results of the revised methodology using the first six months of the next test period (July 2006 through December 2006);
(b) continue to work with the Public Staff and other interested intervenors on the methodology and file on August 15, 2007, the study results for the entire test period (July 2006 through June 2007);
(c) continue to work with the parties on the study methodology until it files its testimony for the next fuel adjustment in September 2007; and

6. To the extent the Public Staff or other interested intervenors disagree with the Company's proposed methodology, they may file their own methodology and its results in testimony in the next fuel adjustment proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr122206.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 436

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	)	

ELECTRIC – ADJUSTMENT OF RATES

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 22, 2006, after public hearing, approving a $20,811,026 increase in the annual rates and charges paid by customers of Dominion North Carolina Power in North Carolina. The rate increase will be effective for usage on and after January 1, 2007. 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, 2006, and represents changes experienced by the Company with respect to its reasonable costs of fuel and fuel component of purchased power.

The change in the approved fuel charge will result in a monthly net increase of approximately $4.94 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of December, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr122206.01

DOCKET NO. E-2, SUB 863

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of John B. Jaske, 20019 Springhill Lane, Rapidan, Virginia 22733, Complainant v. Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., Respondent	)	ORDER REQUIRING REFUNDS

HEARD: Wednesday, June 22, 2005, at 9:00 a.m., in Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner James Y. Kerr, II, Presiding, and Commissioners Sam J. Ervin, IV, and Robert V. Owens, Jr.

APPEARANCES: For Complainant:

John B. Jaske, 20019 Springhill Lane, Rapidan, Virginia 22733, representing himself

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

Len S. Anthony, Deputy General Counsel - Regulatory Affairs, Post Office Box 1551, Raleigh, NC 27602

BY THE COMMISSION: By letter filed with the Commission on February 28, 2005, John B. Jaske (Complainant) initiated a complaint against Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), concerning an assessment that PEC had made for installing a new underground electrical line to Complainant's house on Bald Head Island. The complaint was served on PEC by Commission Order of March 2, 2005.

PEC filed its Answer and Motion for Judgment on Pleadings on March 21, 2005, which was served on Complainant by Commission Order dated March 23, 2005. On April 5, 2005, Complainant filed a Response to Respondent's Answer and Motion for Judgment on the Pleadings and Cross Motion for Judgment on the Pleadings or, in the Alternative, for a Hearing.

On April 14, 2005, the Commission issued an Order Denying Motions for Judgment on the Pleadings and Scheduling Docket for Hearing. The original hearing date was postponed, at Complainant's request, by Order dated May 4, 2005, and the hearing was rescheduled for June 22, 2005.

The hearing was held as scheduled. The parties stipulated to two exhibits, a map of the area involved and PEC's March 24, 2004 letter to Complainant. Complainant testified in his own behalf, and PEC offered the testimony of witnesses Bill White and Greg Cagle. After the hearing, Complainant filed a brief and PEC filed a proposed order.

Based on the pleadings and the testimony and exhibits presented at the hearing, the Commission makes the following:

FINDINGS OF FACT

1. PEC is a public utility providing electric service to customers in North Carolina, including customers on Bald Head Island, subject to the jurisdiction of this Commission.

2. Complainant John B. Jaske is a residential customer of PEC taking service at a house on lot 1245 on Bald Head Island. He has owned the lot about three years. Lot 1245 (also referred to as lot 226 and as 226 West Bald Head Wynd) is between Bald Head Wynd and Sand Piper Trail, and it has frontage on both streets. Complainant's lot was originally on the second row of lots from the ocean, but the lots on the first row, between Sand Piper Trail and the Atlantic Ocean, were never developed.

3. PEC installed an underground electrical distribution system on Bald Head Island in the 1980s. The distribution system included underground lines along Sand Piper Trail and a transformer located on lots 1244 and 1245 near Sand Piper Trail. These were the facilities that originally served the lots of Complainant and his neighboring property owners.

4. After PEC installed the distribution system, the high tide line of the Atlantic Ocean moved steadily inland at that part of the island. By March 2004, the high tide line had crossed the first row of lots and Sand Piper Trail and was up to Complainant's lot. Beach renourishment has since moved the high tide line further out, but Complainant and his neighbors are now oceanfront. The original first row of lots and the part of Sand Piper Trail that once ran by Complainant and his neighbors are now covered with sand.

5. As the ocean advanced, underground lines in the area were sometimes left exposed by erosion. PEC reburied lines that had been exposed and made various attempts to maintain the facilities. By early 2004 PEC's distribution facilities along Sand Piper Trail were under water and the transformer near Sand Piper Trail was about to be underwashed.

6. The situation in early 2004 posed a danger to the public. PEC disconnected service to Complainant and three of his neighbors and abandoned that part of its distribution system along Sand Piper Trail serving these customers. PEC designed and installed new underground distribution lines and a new transformer to serve these customers from the Bald Head Wynd side of their properties. Neither Complainant nor his neighboring property owners requested that the facilities be moved.

7. PEC wrote letters to Complainant and the three other affected property owners informing them that they would need to pay allocated shares of the cost to install new distribution facilities to serve their lots. The letters cited PEC's Line Extension Plan as authority for the charges. Complainant's letter was dated March 24, 2004, and a bill for $2,636.68 was attached to it.

8. Complainant paid the charges billed by PEC, and service was restored to his house. However, Complainant disputes PEC's authority to charge its customers for the relocation of the facilities, and he seeks a refund.

9. The Commission concludes that PEC's tariffs do not authorize it to charge its customers for the relocation of the facilities eroded away by the ocean in this case and that refunds with interest must be made to Complainant and the similarly situated neighboring property owners.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The findings of fact are based upon the testimony and exhibits of Complainant and PEC's witnesses. There is little dispute as to the crucial facts[1]; the primary issue concerns the application of PEC's tariffs.

Complainant argues that none of PEC's tariffs authorizes PEC to charge him for moving the lines and transformer. Complainant contends that the relocation of these facilities was nothing more than maintenance and that maintenance -- whether necessitated by age or by damage due to fire, flood, wind, or erosion -- is PEC's responsibility.

PEC concedes that its tariffs do not specifically address the situation where ocean encroachment requires the abandonment and relocation of electric lines and that this complaint presents a matter of first impression. However, PEC cites several provisions from its tariff and argues that "the logical conclusion of those [tariffs] in theory is the position we have taken here."

The Commission agrees with Complainant that the relocation of the facilities at issue constituted maintenance for which PEC is responsible. At the hearing, PEC witness Cagle could not convincingly distinguish this case from a natural disaster such as a tornado hitting a portion of a metropolitan area. When asked if PEC would charge the customers if it had to relocate facilities as a result of a tornado, Cagle answered, "I'm not sure that I could say for sure we would or would not charge them....But if you are talking about a feeder or something like that that serves a large number of customers and it's knocked down as a result of a hurricane or something, we would put it back up and consider that to be normal maintenance." The applicable tariff is therefore Section 12(a) of PEC's Service Regulations.

Section 12(a) provides, "Company shall install, own, operate, and maintain all lines and equipment located on its side of the point of delivery." This tariff reflects basic principles of public utility law. In general, an electric public utility such as PEC is obligated to provide electric service to all those in its service territory who apply for service. The utility is responsible for extending basic service to customers on an equal basis with the cost of providing such basic service spread over the utility's entire customer base. The utility is responsible for providing and maintaining the necessary facilities up to the point of delivery of electricity to the customer. Inherent in these principles is the further proposition that the public utility essentially takes its service territory as it finds it, including all of its unique geographic, meteorological, and demographic characteristics. Just as the customer who lives near a generating plant pays the same rate as the customer furthest away, so the customers

[1] For example, there was disagreement as to whether the Building Inspector for Bald Head Island ordered PEC to disconnect houses and abandon the distribution facilities in question or whether PEC took it upon itself to do so after the Building Inspector merely told PEC that it "needed to do something"; however, this dispute is not crucial to the reasoning adopted herein.

more susceptible to ice storms or hurricanes or beach erosion pay the same rate as the customers less susceptible to such phenomena. All of these general principles are, of course, subject to any tariffs that have been approved by the Commission to address specific situations or specific costs, but PEC has no specific tariff addressing the facts of this case. PEC tries to use tariffs written for other situations to charge Complainant for the relocation of the facilities necessary to provide him with electric service, but the tariffs do not support PEC's position.

Utility tariffs are to be interpreted according to the rules for interpretation of contracts, State ex rel. Utilities Comm. v. Thrifty Call, 154 NCApp 58, 63 (2002), dis. rev. denied, 357 NC 66 (2003), and there is a large body of case law addressing the interpretation of contracts. See, e.g., 6 Strong's NC Index 4th, Contracts §§ 52-78 (2002); 17A AmJur2d, Contracts §§ 328-499 (2004). Woods v. Insurance Co., 295 NC 500 (1978), which involved an insurance policy, summarizes several general principles for construction of contracts and is helpful here:

> As with all contracts, the goal of construction is to arrive at the intent of the parties when the policy was issued. Where a policy defines a term, that definition is to be used. If no definition is given, non-technical words are to be given their meaning in ordinary speech, unless the context clearly indicates another meaning was intended. The various terms of the policy are to be harmoniously construed, and if possible, every word and every provision is to be given effect. If, however, the meaning of words or the effect of provisions is uncertain or capable of several reasonable interpretations, the doubts will be resolved against the insurance company and in favor of the policyholder. Whereas, if the meaning of the policy is clear and only one reasonable interpretation exists, the courts must enforce the contract as written; they may not, under the guise of construing an ambiguous term, rewrite the contract or impose liabilities on the parties not bargained for and found therein.

Id at 505-6. Applying the principles of construction to PEC's tariffs, the Commission concludes that the tariffs do not support PEC's arguments.

PEC's letter to Complainant cited its Line Extension Plan as authority for the charges. Section III.A.2 of the Plan states in part, "When it is necessary to relocate the primary distribution facilities serving any customer-requested facilities...for the Customer's convenience, the Customer shall pay the amount by which the Construction Cost exceeds Revenue Credit..." PEC argues that the relocation of the facilities herein was undertaken for the "Customer's convenience" since the work satisfied Complainant's continuing need for electric service. Section III.E.4 of the Plan states, "When the Company's existing facilities within a Real Estate Development must be rearranged and/or abandoned due to any actions of the original owner or developer or any subsequent owner(s) or developer(s) within the development, the party requesting the changes shall pay...." Complainant did not request that PEC relocate the facilities, but PEC argues that that is immaterial since Complainant clearly wanted to continue receiving electric service. The Commission concludes that these tariffs do not apply to the facts of this case.

PEC's own testimony establishes that the facilities were relocated for reasons of public safety. PEC witness White testified that once he became aware of the situation in early 2004, it was not possible to leave the facilities in place because of safety and engineering guidelines. He stated, "I went by and inspected the area and we could not leave it as it was exposed to the public." When asked if the facilities could have been maintained in place in compliance with safety guidelines, he answered, "No....it became a danger from where it was. Secondary voltage and primary voltage are two different things. Primary voltage, to have a transformer loss right there, you are talking about some grave danger from 15,000 volts." White testified that PEC made various attempts to maintain the facilities and that "we try to keep it as safe as we can to the public. And when we get to a point where we can't do anything else to it, then we have [to] disconnect them." The relocation here was necessitated by PEC's obligation to serve within its service territory and to do so in a manner that meets safety requirements and protects the public from danger. By no reasonable interpretation of its tariffs can PEC construe such a fundamental public utility obligation as a matter of mere customer convenience or request. Neither Section III.A.2 nor Section III.E.4 was ever intended for a situation where the original means of providing service has become a danger to the public and must be relocated for that reason. These tariffs are typically applied in situations where the original means of service is still available and adequate, but the customer (or developer) requests that the utility's facilities be moved for his own purposes (for example, when a service line is moved to accommodate the building of a home addition or a garage). In such a case, the customer alone has caused the relocation costs to be incurred, and it follows that the customer should bear those costs. The customer should not bear the costs of a relocation undertaken because the utility's facilities, for reasons unrelated to any acts of the customer, have become unsafe.

At the hearing, PEC relied upon other provisions of its tariffs which were not mentioned in the letter to Complainant -- Section 1(h), Section 2(d), and Section 12(d) of PEC's Service Regulations. For the reasons discussed below, the Commission concludes that none of these tariff provisions applies to this case.

PEC witness Cagle cited Section 1(h) of PEC's Service Regulations, which gives PEC the right to terminate service under certain circumstances, including "in case of a condition on Customer's side of the point of delivery actually known by Company to be, or which Company reasonably anticipates may be, dangerous to life or property." When questioned, Cagle quickly backed off reliance on this tariff, conceding, "Well, quite honestly, we are talking here about a condition that existed on our side of the point of delivery." This tariff does not avail PEC because (1) it does not address unsafe conditions on the utility's side of the delivery point, where the utility is responsible for maintenance, and, in any event, (2) it does not address the question of costs which is the issue here.

Section 2(d) of PEC's Service Regulations states that PEC may discontinue service to a customer who is served by lines that cross government land

> if and when (1) Company is required by governmental authority to incur expense in the relocation or the reconstruction underground of any portion of said lines, unless Company is reimbursed for such expense by Customer or Customers served therefrom, or (2) the right of Company to maintain and operate said lines shall be terminated, revoked, or denied by governmental authority for any reason.

First, the Commission notes that this tariff does not authorize the charges billed by PEC since not all of the relocated facilities were originally in the public street: some underground lines were in the street right of way, but the transformer was on private property. More to the point, the Commission concludes that this tariff is typically applied where the original means of service would still be available <u>but for</u> the act of the governmental authority, and that is not the case here. Here, there is a dispute as to whether the local building inspector's communication to PEC amounted to an order; PEC contends that the Island's Building Inspector told PEC that "you're going to have to do something" and that this constituted a denial of PEC's right to operate the existing lines on Sand Piper Trail. However, as discussed above, PEC witness White testified that, once he became aware of the situation, it was not possible to leave the facilities "as it was exposed to the public" because of safety and engineering guidelines. Thus, regardless of what the building inspector said, the real reason PEC relocated the facilities was that erosion had rendered them dangerous to the public, and Section 2(d) does not speak to a situation where PEC relocates facilities for reasons of public safety. As a public utility, PEC has an obligation to serve and to do so safely, and PEC cannot argue that acts undertaken to meet that fundamental responsibility were in fact undertaken at the behest of the local government.

Finally, Section 12(d) of PEC's Service Regulations provides as follows:

> Protection: Customer shall protect Company's wiring and apparatus on Customer's premises and shall permit no one but Company's agents to handle same. In the event of any loss or damage to such property of Company caused by or arising out of carelessness, neglect, or misuse by Customer, his employees or agents, the cost of making good such loss or repairing such damage shall be paid by Customer. In cases where Company's service facilities on Customer's premises require abnormal maintenance due to Customer's operation, Customer shall reimburse Company for such abnormal maintenance.

PEC cites the last sentence of the tariff. Again, the Commission concludes that this tariff does not apply to the facts of this case. First, the sentence cited by PEC refers to utility facilities "on customer's premises." Not all of the relocated facilities were originally on Complainant's property; many of them were in the street right of way. Second, this sentence is in a tariff entitled "Protection," and the previous sentence speaks to a customer's responsibility to protect the utility's equipment from loss or damage caused by the customer's negligence or misuse. There is no evidence that Complainant was negligent or that he misused the facilities that had to be relocated. Third, all of that aside, the only abnormal maintenance that the last sentence charges to the customer is abnormal maintenance "due to Customer's operation." PEC witness Cagle testified that since the facilities serving Complainant had to be redesigned and moved, "it is certainly abnormal maintenance," and PEC's proposed order tries to apply this tariff by arguing that "Customer's operation" should be interpreted as referring to the fact that Complainant wanted electric service in an "unusual and abnormal location," i.e., oceanfront property subject to erosion. PEC is again taking a tariff that was written for another situation and trying to invoke it in a situation where it does not apply. The language of contracts and tariffs should be read in context and ordinary words should be given their ordinary meaning. Section 12(d) does not apply here because the phrase "Customer's operation" was never intended to include merely living at the beach, and it cannot be interpreted in that manner.

In summary, the relocation of the lines and transformer serving Complainant was maintenance necessitated by natural forces beyond the utility's or customer's control. It was similar to the reburying of lines that PEC had done before on Bald Head Island -- for which it did not charge customers -- and similar to the rebuilding in communities both modest and affluent that PEC does after a hurricane or tornado -- for which it does not charge customers. PEC is responsible for such maintenance under general principles of public utility law and under its own tariffs, and PEC must make a refund to Complainant. PEC shall also make refunds to the similarly situated neighboring property owners who were charged for the relocation of the facilities at issue in this case to the extent that they paid the charges billed and that PEC finds no distinguishing issues of fact as to them. G.S. 62-132.

IT IS, THEREFORE, ORDERED that the complaint filed in this docket on February 28, 2005, should be, and hereby is, allowed and that PEC shall make refunds, with 10% interest pursuant to G.S. 62-130(e), to Complainant and to the similarly situated neighboring property owners who were charged for the relocation of the facilities at issue in this case.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of February, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Gr020606.02

DOCKET NO. E-7, SUB 795A
DOCKET NO. E-7, SUB 810

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 795A In the Matter of Application of Duke Energy Corporation for Approval of Form Service Agreements and the List of Services Duke Power, LLC Intends to Take or Provide Under These Agreements and a Ruling That the Services Described in the Utility Service Agreement are Shared Services Under the Regulatory Conditions and Code of Conduct DOCKET NO. E-7, SUB 810 In the Matter of Advance Notice of Initial Transfer of Services, Functions and Employees from Duke Energy Corporation to Duke Energy Business Services, LLC, and Duke Energy Shared Services, Inc.	)	ORDER ACCEPTING AFFILIATE AGREEMENTS FOR FILING AND ALLOWING PAYMENTS THEREUNDER

BY THE COMMISSION: This matter concerns the request by Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (Duke Power or Company) for Commission approval of certain service agreements between and among Duke Power and its affiliates and the lists of goods or services Duke Power intends to receive and provide under these service agreements pursuant to G.S. 62-153 and Regulatory Condition No. 20. According to Duke Power, these service agreements are proposed in order to take advantage of the potential synergies and cost savings associated with the merger of Duke Energy Corporation and Cinergy Corp. by combining similar corporate functions. In addition, Duke Power also requests that the Commission find that the services described in one of the service agreements constitute "Shared Services" under the Regulatory Conditions and Code of Conduct previously approved by the Commission in Docket No. E-7, Sub 795.

BACKGROUND

On February 1, 2006, Duke Power filed final forms of service agreements that authorize the provision and receipt of non-power goods and services between and among Duke Power, its Affiliates and Nonpublic Utility Operations[1], the lists of goods and services it intends to take from Duke Energy Shared Services, LLC (Duke Services), and the basis for the determination of such lists. In addition, Duke Power also filed the lists of goods and services it intends to offer its Affiliates and take from Affiliates other than Duke Services. This filing was made pursuant to the requirements of Regulatory Condition No. 20 and G.S. 62-153.

More specifically, Duke Power's filing included the following service agreements and lists of services:

[1] These words and phrases are defined in the Regulatory Condition and Code of Conduct approved by the Commission Order dated March 24, 2006 in Docket No. E-2, Sub 795.

1. Attachment 1 – The Service Company/Utility Service Agreement, including Appendix A and Appendix B (Utility Service Agreement), which will govern the provision of services from Duke Services to Duke Power and other regulated utility affiliates following consummation of the merger.

2. Attachment 2 – The list of services Duke Power intends to take from Duke Services under the Utility Service Agreement.

3. Attachment 3 – The Operating Companies Service Agreement (Operating Companies Agreement), which is an agreement between and among Duke Power, The Cincinnati Gas and Electric Company (CG&E), PSI Energy, Inc. (PSI), Union Light, Heat and Power Company (Union), and Miami Power Corporation (Miami). Under this agreement, the utilities are permitted to perform services for one another.

4. Attachment 4 – The list of services Duke Power intends to take from and provide to utility affiliates under the Operating Companies Agreement.

5. Attachment 5 – The Operating Company/Nonutility Companies Service Agreement, which will allow Duke Power to provide services to various non-regulated affiliated companies and vice versa. Duke Power does not intend to take or provide any services under this agreement at this time.

6. Attachment 6 – The Service Company/Nonutility Service Agreement, which will govern the provision of services from Duke Services to non-utility affiliates of Duke Power following consummation of the merger.

The filing further indicates that the key driver in the determination of which services Duke Power will take from Duke Services is the identification of the functions that will be performed for more than one operating or nonutility company. As proposed, the employees that perform functions for more than one operating company will be employed by Duke Services.

According to this filing, similar functions across Duke Energy Corporation (Duke Energy) and Cinergy Corp. will be combined where doing so is expected to result in cost savings. Many corporate functions, such as corporate finance, legal and human resources, are already provided to Duke Power under an affiliate agreement with Duke Energy Business Services, LLC (DEBS), pursuant to which payment was allowed by the Commission in Docket No. E-7, Sub 658. With regard to the determination of which services Duke Power will take from Duke Services, the filing indicates that the key is the identification of which functions will be performed for more than one utility or nonutility company. As proposed, the employees performing such functions will be employed by Duke Services.

Duke Power's February 1, 2006 filing also explains a transition plan which is necessary due to certain provisions in the merger agreement between Duke Energy and Cinergy Corp. that result in a need for a period to fully transition all employees providing the shared services to one legal entity. Additionally, due to tax considerations, Duke Power's filing states that there may be a need to keep employees in their existing companies until January 1, 2007. Effective January 1, 2007, Duke Energy intends to have all personnel performing service company activities employed by either DEBS or

Duke Services. Effective January 1, 2008, Duke Energy intends to fully transition to one shared services legal entity, which will be Duke Services.

In summary, Duke Power requests that the Commission approve the Utility Service Agreement, the Operating Companies Agreement, the Operating Company/Nonutility Companies Service Agreement, and the lists of services Duke Power intends to take or provide under these agreements. In addition, Duke requests that the Commission find that the services described in the Utility Service Agreement constitute "Shared Services" under the Commission-approved Regulatory Conditions and Code of Conduct.

On March 1, 2006, Duke Power filed an advance notice to comply with Regulatory Condition No. 55 (which initiated Docket No. E-2, Sub 810). In the advance notice filing, Duke Power stated that it intended to transfer certain functions and employees from Duke Power to DEBS and Duke Services on or about April 1, 2006 during a transition period which was necessitated by certain provisions in the merger agreement, as explained in its filing dated February 1, 2006.

On March 23, 2006, Duke Power filed a notice explaining that it planned to operate under the Service Agreements on an interim basis pursuant to Regulatory Condition No. 20(b). Duke Power acknowledged that such interim operation does not constitute acceptance or approval of the Service Agreement under G.S. 65-153 or preclude the Commission from addressing any issue raised by intervenors. Duke Power further acknowledged that such interim operation under the Service Agreements would be subject to refund and subject to any fully adjudicated Commission order on this matter.

Also on March 23, 2006, the Public Staff filed a response to Duke Power's filings dated February 1, 2006 and March 1, 2006. In its response, filed pursuant to Regulatory Condition Nos. 20(b) and 55, the Public Staff recommended that the Commission issue a procedural order as described in its filing.

On March 30, 2006, the Commission issued an Order Establishing Procedures in this matter. Said Order: required Duke Power to file any revisions or clarifications to its February 1, 2006 filing in Docket No. E-2, Sub 795A and to its March 1, 2006 filing in Docket No. E-2, Sub 810 within ten days of the date of the Order, established a schedule for the filing of comments and reply comments, and stated that any objections filed pursuant to Duke Power's advance notice filed in Docket No. E-2, Sub 810 would be handled in accordance with Regulatory Condition No. 59(b).

On April 10, 2006, Duke Power filed a number of revisions to the service agreements and lists of services filed in Docket No. E-2, Sub 795A and in the lists of functions and employees included in the advance notice of initial transfer filed in Docket No. E-2, Sub 810.

On April 24, 2006, the Public Staff filed a conditional objection in response to Duke Power's advance notice of initial transfer. In its filing, the Public Staff stated that the filings by Duke Power in Docket Nos. E-2, Sub 795A and Sub 810 are intrinsically related because the services, functions and employees proposed to be transferred in Sub 810 are for the purpose of combining numerous functions in Duke Services, from which Duke Power will take various services pursuant to the Utility Service Agreement and list of services filed in Sub 795A. The Public Staff stated that certain items in the list of services filed by Duke Power on February 1, 2006 (as amended on April 10, 2006) presented no issues, while other items raised a number of issues. The Public Staff stated that such issues would be addressed in its comments to be filed at a later date as allowed by the Commission's Order Establishing Procedures dated March 30, 2006.

On May 16, 2006, the Public Staff filed comments in which it raised several issues related to the Service Agreements. On that same date, the Carolina Utility Customers Association, Inc. (CUCA) also filed comments and raised an issue as to whether or not the asymmetric pricing provisions in Duke's Commission-approved Code of Conduct should apply to each transaction pursuant to the Service Agreements involving Duke.

On May 31, 2006, Duke Power filed reply comments. In addition, Duke Power's reply comments included two attachments. Attachment A includes a revised list of services for the Operating Companies Agreement and the Operating Company/Nonutility Companies Service Agreement and (2) a description of the charging and accounting treatment the Company plans to use for joint project development projects that serve to benefit all of the participants in a project. Attachment B includes a description of certain additional employees to be transferred from Duke Power to Duke Services.

On June 6, 2006, the Commission issued an Order in which it noted that the comments of the Public Staff and CUCA and the reply comments of Duke Power revealed that numerous issues then existed among the parties as to whether the Commission should approve the Service Agreements and transfers and/or whether additional conditions should be required. Further, based upon its examination of those comments, the Commission stated its belief that this was an appropriate case in which to urge the parties to attempt to negotiate the issues. Therefore, the Commission required the parties to meet and negotiate, with a view toward resolving or simplifying the issues, and then file further comments advising the Commission as to agreements reached and stating their positions on matters still in dispute.

On July 27, 2006, CUCA filed further comments in which it stated that the negotiations of CUCA and Duke Power were unsuccessful and that CUCA's position on the issue identified in its comments filed on May 16, 2006 has not changed.

On July 28, 2006, the Public Staff filed its further comments and reported that Duke Power and the Public Staff had resolved all outstanding issues between them as discussed below.

Duke Power also filed further comments on July 28, 2006. In its further comments, Duke Power stated that it was able to resolve the issues raised by the Public Staff and had reached agreement as to certain changes and conditions that are set forth in the Public Staff's further comments. Duke Power also noted that negotiations with CUCA were unsuccessful. By reference, Duke Power incorporated the arguments contained in its reply comments filed on May 31, 2006 to address the outstanding issue raised by CUCA.

On August 18, 2006, the Commission issued an Order which scheduled an oral argument to consider the issues which remained in dispute after negotiations.

On September, 5, 2006, the Commission issued an Order canceling the oral argument based upon further review of written comments.

DISCUSSION

In the remaining section of this Order, the agreements of Duke Power and the Public Staff will be set forth and addressed by the Commission. In addition, the issue raised by CUCA, which is now ripe for decision, will be discussed and addressed.

Agreements of Duke Power
and the Public Staff

As noted above, Duke Power and the Public Staff resolved all outstanding issues between them according to the reply comments filed by each of these parties on July 28, 2006. Their agreements as to certain changes and conditions, which are set forth in the Public Staff reply comments or in the Public Staff's comments filed on May 16, 2006, are described below.

Attachment 1 – Utility Service Agreement

In comments filed on May 16, 2006, the Public Staff questioned whether Section 5.7 of the Utility Service Agreement, as filed by Duke Power on February 1, 2006, complies with the Regulatory Conditions and is sufficient to protect the Commission's jurisdiction from preemption. However, Duke Power included a revised Section 5.7 in its filing on April 10, 2006. With this revision, the Public Staff believes that the Utility Service Agreement complies with the Regulatory Conditions and is sufficient to protect the Commission's jurisdiction from preemption.

With respect to whether Duke Power's proposed transition plan requires any changes to the Utility Service Agreement, the Public Staff reported that the addition of DEBS as a party to the Utility Service Agreement substantially resolved its concern. However, the Public Staff recommended that (a) the Commission should make it explicit in any order accepting the Utility Service Agreement that, during the transition period, DEBS is to be subject to the same Regulatory Conditions and other conditions to which Duke Services is subject and (b) Duke Power should be required to file a notice with the Commission within 30 days of fully transitioning to Duke Services being the only shared services legal entity.

Section 2.2 of the Utility Service Agreement provides for the service company's ability to make material changes to methods of cost assignment, distribution or allocation. The Public Staff stated that the sentence added to 2.2, along with the revised section 5.7, are sufficient to ensure that the service company cannot make changes without complying with the Regulatory Conditions and the Code of Conduct.

Appendix A to the Utility Service Agreement

In its comments filed on May 16, 2006, the Public Staff expressed concern as to whether the statement at the top of page 9 in Appendix A, regarding substitution or changes in allocation, complies with the advance notice and approval provisions of Regulatory Condition No. 20. According to the Public Staff's further comments filed on July 28, 2006, the Public Staff and Duke Power have agreed to resolve this concern by adding the following language in Appendix A: "Any such substitution or changes shall be in compliance with the requirements of applicable state law, regulations and regulatory conditions.

Attachment 2 – List of Services under the Utility Service Agreement

According to the comments of the Public Staff filed on May 16, 2006, the extent to which the activities undertaken by the service company might render it a public utility under the Federal Power Act or cause the Utility Service Agreement to be considered an integration agreement subject to the FERC's jurisdiction is an important issue. However, given the revisions filed by Duke Power on April 10, 2006, the Public Staff does not believe that the activities included in the service agreement would render Duke Services a public utility under the Federal Power Act or cause the agreement to be considered an integration agreement. In addition, Regulatory Condition No. 20 requires changes to the list of services to be filed in advance, but does not explicitly require notice or approval of changes to the agreement itself. Because of the importance of this issue, any future changes to the agreement or list of services must be carefully scrutinized. According to the further comments of the Public Staff filed on July 28, 2006, Duke Power and the Public Staff have also agreed to the following conditions related to preemption:

(1) Consistent with G.S. 62-153, Duke Power shall obtain prior approval of any proposed ***substantive*** revisions to the Utility Service Agreement and in the contractual relationship between it and Duke Services.

(2) Duke Power shall obtain Commission approval before Duke Services or DEBS are sold, transferred, merged with any other entities, have any ownership interest therein changed, or otherwise changed so that a change of control could occur. This requirement does not apply to the currently planned merger of DEBS into Duke Services or any movement of DEBS or Duke Services within the Duke Energy corporate organization ~~for tax purposes~~ ***that does not constitute a change of control.***

In its comments filed on May 16, 2006, the Public Staff noted that the service company would perform a number of services for both regulated utilities and nonregulated affiliates and operations. This caused the Public Staff to express concern with respect to priority of service. According to the further comments of the Public Staff filed on July 28, 2006, the Public Staff and Duke have agreed to the following condition relating to priority of service and applicable to Items 7, 12 and 20 in Attachment 2 – List of Services.

Duke Power, Duke Services, and Duke Energy Corporation shall ensure that Duke Power's regulated native load operations will be assigned the highest priority of all work, services, or projects with respect to Item 7 – Power Engineering and Construction, Item 12 – Power Planning and Operations, and Item 20 – Fuels performed or to be performed by Duke Services vis-à-vis non-regulated operations and that Duke Power's regulated native load operations will be treated no less favorably than the regulated native load generation-related operations of PSI and Union and the generation-related operations of CG&E as specified herein. For purposes of this condition, CG&E's generation-related operations are limited to the generating units considered to be in its rate base at the time Ohio's electric restructuring legislation was implemented (August 31, 2000), and only to the extent that these units (a) are considered physically dedicated to serving retail load in CG&E's service territory and subject to the rate stabilization plan market based standard service offer (as approved in Case 03-93-ATA) or (b) again become subject to traditional regulation. After

December 31, 2008, Commission approval must be obtained to continue treating the foregoing CG&E generation-related operations as regulated operations. CG&E generating units that do not meet the foregoing requirements shall be treated as non-regulated operations except that, solely for reliability purposes, Duke Services, in its performance of the relevant activities under Item 12(2) and (3), may give those generating units priority equal to the priority given to the regulated operations of Duke Power, PSI and Union. Any party may request that the Commission alter the foregoing limitations based upon subsequent developments or changes in Ohio with respect to the treatment of CG&E's generating units. The burden shall be on Duke Power to establish that it received the priority required by this condition and that CG&E's previously rate based generating units are, and remain, physically dedicated to serving retail load in CG&E's service territory during the rate stabilization period.

In addition, several items in Attachment 2 present an issue concerning the extent to which the service company should be allowed to file joint comments and make other filings with the FERC, according to the comments of the Public Staff filed on May 16, 2006. However, the further comments of the Public Staff filed on July 28, 2006 state that the Public Staff and Duke Power have agreed to the following condition with respect to joint filings:

> Duke Power may participate in joint comments and other joint filings with Affiliates only when such participation fully complies with both the letter and the spirit of the Regulatory Conditions. Any filing made by Duke Services on behalf of Duke Power, or in which Duke Power participates, must clearly identify Duke Services as an agent of Duke Power for purposes of making the filing.

Item 5 in Attachment 2 is Marketing and Customer Relations, which includes the design of sales and demand-side management programs, customer meter reading, bill and payment processing, and customer services, including the operation of call centers. To the extent that the provision of these services necessitates or otherwise results in the disclosure of Duke Power's Customer Information to Duke Services, such disclosure and Customer Information must be administered and managed in accordance with the Code of Conduct. According to the comments of the Public Staff filed on May 16, 2006, as well as its further comments filed on July 28, 2006, the Public Staff and Duke Power have also agreed to the following conditions, which address information sharing and direction:

(1) No Duke Services employee may use Customer Information to ~~discuss,~~ market~~,~~ or sell any product or service to Duke Power's customers, ***except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by Duke Power.***

(2) Duke Services employees with access to Customer Information must be prohibited from making any ***<u>improper</u>*** indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of Duke Services that do not have access to such information, or by other employees of Duke Energy (holding company) or other Affiliates or Nonpublic Utility Operations of Duke Power.

(3) Duke Power must file in this docket, within 60 days of any Commission Order permitting the provision of services as described in Item 5, a copy of the guidelines established for Duke Services employees with regard to complying with the Customer Information Section of the North Carolina Code, a narrative explanation of the training to be given Duke Services employees regarding such compliance, and a copy of any documents provided to employees in the course of that training.

(4) Should any inappropriate disclosure of Duke Power Customer Information occur at any time, Duke Power is required to ~~immediately~~ ***promptly*** file a statement with the Commission in this docket describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

In its comments filed on May 16, 2006, the Public Staff noted that Item 4 (Electric System Maintenance), Item 6 (Electric Transmission and Engineering and Construction), Item 7 (Power Engineering and Construction), and Item 12 (Power Planning and Operations) in Attachment 2 are interrelated. According to the Public Staff, the coordination of maintenance services between and among Duke and the Affiliates raises a number of issues with respect to priority of service; how closely maintenance services need to be coordinated with the functions and services in Item 6, Item 7, and Item 12; and conditions to govern any sharing of Duke Power's Confidential Systems Operation Information (CSOI) and other sensitive information. The Public Staff added that Item 12 causes the most concern of all the items listed in Attachment 2. More than any of the other Attachment 2 items, and more than has been attempted by Progress Energy Carolinas, Inc. or Dominion North Carolina Power, Duke Power's proposal moves essential core utility operations to a separate corporate entity. Therefore, the Public Staff believes this situation must be closely monitored. The Public Staff also stated that Duke Power must be able to demonstrate on an ongoing basis that its proposed organization is more beneficial to its North Carolina retail ratepayers than any other feasible organizational structure, including one that moves all the power planning and operations functions back to the Duke Power corporate entity. In addition, the Public Staff recommended that certain additional conditions are necessary with respect to priority of service (as set forth above) and the protection of CSOI and other sensitive information (as set forth below). The Public Staff also expressed concern with regard to specific wording which was originally used in Item 12. The phrase included in section (a), "Duke Energy Corporation's electric generation units and transmission and distribution systems", concerns the Public Staff because such language could be interpreted as being inconsistent with the Regulatory Conditions and conveys the impression that there is one Duke Energy power system rather than separate systems operated by individual utilities. Instead of this phrase, the Public Staff recommended more precise wording, such as "the electric generation units and transmission and distribution systems belonging to the regulated utilities owned by Duke Energy Corporation." In its reply comments filed on May 31, 2006, Duke Power agreed to make this change in language to clarify Item 12.

The Public Staff also expressed concerns with respect to Item 20 (Fuels) in Attachment 2 in at least 2 respects. First, as with the power planning and operations functions and services proposed to be transferred in Item 12, fuel procurement is a core utility function. Second, the Code of Conduct permits joint purchases of coal (explicitly) and oil (implicitly, by the lack of any prohibition) directly between Duke, PSI, and Union; however, it does not permit joint purchases of natural gas, according to the Public Staff. In addressing these concerns, the Public Staff stated that, at a minimum, (a) the nonregulated business operations cannot be allowed to participate with the regulated utilities in this joint procurement, (b) CSOI and other sensitive information cannot be directly or indirectly shared with the nonregulated operations in contravention of North Carolina and FERC Codes and Standards of Conduct and conditions recommended elsewhere in its comments, and (c) no personnel that are involved in fuel procurement for the utilities can also be involved in fuel procurement for the nonregulated operations. The Public Staff also stated again that Duke Power must be able to demonstrate on an ongoing basis that its proposed organizational structure is more beneficial to its North Carolina retail ratepayers than any other organizational structure, including one that moves all Duke Power fuel procurement back to the Duke Power corporate entity. In addition, according to the further comments of the Public Staff filed on July 28, 2006, the Public Staff and Duke Power have agreed that Section D.(5). of the Code of Conduct should be revised to address joint fuel purchases, as follows:

> D.(5). Duke Power and its Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of ***(a) electricity and ancillary services intended for resale,*** ***(b)*** natural gas, and ***(c)*** coal ~~electricity and ancillary services intended for resale~~), if such joint purchases result in cost savings to Duke Power's Customers. Duke Power, PSI Energy, Inc., and Union Light, Heat and Power Company may capture economies-of-scale in joint purchases of ***natural gas for consumption and*** coal ***for consumption***, if such joint purchases result in cost savings to Duke Power's Customers. Notwithstanding the foregoing, if any of the **natural gas or** coal jointly purchased by Duke Power, PSI Energy, Inc., and Union Light, Heat and Power Company, is transferred to or utilized by another Affiliate within 12 months of the joint purchase, Duke Power will file a notification of such with the Commission.

The Public Staff also pointed out that the provision of the services to be provided to Duke Power by Duke Services in Items 4, 6, 7, 12 and 20 may cause certain employees of Duke Services to come into possession of Duke Power CSOI. In addition to applicable provisions of the Code of Conduct, the further comments of the Public Staff filed on July 28, 2006 state that the Public Staff and Duke Power have agreed to the following CSOI conditions:

(1) Duke Services employees with access to CSOI must be prohibited from making any ***<u>improper</u>*** indirect use of the data, including directing or encouraging any actions based on the CSOI by employees of Duke Services that do not have access to such information, or by other employees of Duke Energy (holding company) or other Affiliates or Nonpublic Utility Operations of Duke Power.

(2) Duke Power shall file in this docket, within 60 days of any Commission Order permitting the provision of services as described in Items 4, 6, 7, 12, and 20, a copy of the guidelines established for Duke Services employees with regard to complying with the CSOI Section of the NC Code, a narrative explanation of the training to be given Duke Services employees regarding such compliance, and a copy of any documents provided to employees in the course of that training.

(3) Should any inappropriate disclosure of CSOI occur at any time, Duke Power shall ~~immediately~~ ***promptly*** file a statement with the Commission in this docket describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the mitigating and/or other steps taken to address the disclosure.

(4) Should the handling or disclosure of Market Information or Transmission Information by Duke Services or its employees result in (a) a violation of the FERC Code or the Transmission Standards, (b) the posting of such data on an OASIS or other Internet website, or (c) other public disclosure of the data, Duke Power shall ~~immediately~~ ***promptly*** file a statement with the Commission in this docket describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the mitigating and/or other steps taken to address the current or any future potential violation, posting, or other public disclosure.

(5) Should Duke Power begin to compete with PSI or Union in the wholesale power sector in more than a very limited manner, Duke Power shall immediately take steps to amend Items 4, 6, 7, 12, and 20, and these conditions, as appropriate, and shall file the amended Items and conditions with the Commission for approval within 60 days of the change in circumstances.

(6) Should either the FERC Code or the Transmission Standards be eliminated, amended, superseded, or otherwise replaced, Duke Power shall file a letter with the Commission in this docket describing such action within 60 days of the action, along with a copy of any amended or replacement document.

<u>Attachment 3 – Operating Companies Agreement</u>

Attachment 3 is the Operating Companies Agreement, which is an agreement between and among Duke Power, CG&E, PSI, Union, and Miami. Under this agreement, the utilities are permitted to perform services for one another. Including Duke Power's revisions to Attachment 3 filed on April 10, 2006 and subject to Duke Power receiving priority of service, the Public Staff does not object to Attachment 3.

<u>Attachment 4 – List of Services under the Operating Companies Agreement</u>
and
<u>Attachment 5 – Operating Company/Nonutility Companies Service Agreement</u>

Attachment 4 is the list of services Duke Power intends to take from and provide to its operating company affiliates under the Operating Companies Agreement. As originally filed on February 1, 2006 by Duke Power, the only service on the list was support during storm recovery.

Attachment 5 is the Operating Company/Nonutility Companies Service Agreement which allows Duke Power to provide services to, and take services from, the non-regulated affiliate companies on the signatory pages of this agreement.

As noted above, Duke Power's reply comments filed on May 31, 2006, included two attachments. Attachment A includes (1) revised lists of services for the Operating Companies Agreement and for the Operating Company/Nonutility Companies Service Agreement and (2) a description of the charging and accounting treatment Duke Power proposes to use for joint project developments that serve to benefit all of the participants in a project. In its reply comments, Duke Power stated that it continues to believe that these services will occur only on an incidental basis. Attachment B includes a description of certain additional employees to be transferred from Duke Power to Duke Services.

With exception to the joint project development language in Attachment A, the Public Staff stated in its reply comments filed on July 28, 2006 that it has no objection to Attachments A and B, so long as it is clear that any such services must be incidental in nature and that Duke Power's regulated operations must receive priority. According to the Public Staff, Duke Power and the Public Staff are still discussing the joint project development language and will file an appropriate amendment to the Code of Conduct at a later date. The Public Staff added that the joint project development language is not part of the service agreement and its resolution should not delay a ruling on the service agreements, lists of services, and transfer of employees.

Further, except as noted above, the Public Staff voiced no objection to Attachment 4 and 5.

Attachment 6 – Service Company Nonutility Service Agreement

Attachment 6 is the Service Company Nonutility Service Agreement which will govern the provision of services from Duke Services to nonutility affiliates. Duke Power's filing on February 1, 2006 states that this agreement is filed for informational purposes only to demonstrate the terms and conditions under which Duke Services will provide the same services to nonutility affiliates that it provides to Duke Power. According to Duke Power, this agreement does not require approval or acceptance by the Commission because Duke Power is not a party to the agreement.

The Public Staff believes that this agreement is an Affiliate Contract, as that term is defined in the Regulatory Conditions, because it is a contract among Duke affiliates and it is reasonably likely to have an Effect on Duke Power's Rates, as that term is also defined in the Regulatory Conditions. The Public Staff contends that, as an Affiliate Contact, it is subject to the provisions of Regulatory Condition No. 1(a). Since service agreements are not required to be filed with the FERC at this time, the Public Staff further believes that Regulatory Condition Nos. 1(c) and 10 would not apply. However, if Duke Power proposes to file the agreement or if the FERC requires such agreements to be filed, the Public Staff states that these two Regulatory Conditions would apply.

Shared Services

In its February 1, 2006 filing, Duke Power also requests that the Commission find that the services described in the Utility Service Agreement constitute "Shared Services" under the Regulatory Conditions and the Code of Conduct.

In its comments filed on May 16, 2006, the Public Staff contended that Duke Power's request with respect to "Shared Services" is overbroad. "Shared Services" are defined in both Regulatory Conditions and Code of Conduct as follows:

> The services that meet the requirements of the Regulatory Conditions approved in Docket No. E-7, Sub 795, or subsequent orders of the Commission and that the Commission has explicitly authorized Duke Power to take from Duke Energy Shared Services pursuant to a service agreement (a) filed with the Commission pursuant to G.S. § 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions, including, but not limited to, Regulatory Condition No. 20 approved in Docket No. E-7, Sub 795.

The Public Staff stated that it has no objection to a finding by the Commission that the specific services that the Commission explicitly allows Duke Power to take pursuant to the Utility Service Agreement are "Shared Services" under the Regulatory Conditions and the Code of Conduct.

Pending Issue of CUCA

In its comments filed on May 16, 2006, CUCA stated its belief that the asymmetric pricing provisions of Section III.D.3(a) and (b) need to be applied to all transactions between Duke Power and its affiliates, including the three affiliate agreements filed by Duke Power for approval. According to CUCA, only the Operating Company/Nonutility Companies Service Agreement expressly incorporates the asymmetric pricing language of the Code of Conduct, while the Utility Service Agreement and the Operating Companies Agreement address pricing of affiliate transactions at cost and fail to explicitly incorporate the asymmetric pricing provisions.

CUCA also stated that Section III.D.4. allows Duke Power to pay for services from affiliates and receive payments for services to affiliates on a cost basis as they are "cost beneficial", subject to Regulatory Condition No. 18. However, CUCA argued that Regulatory Condition No. 18 is subject to the Code of Conduct, which prohibits Duke Power from recovering costs from ratepayers that exceed fair market value for services from affiliates, unless the services are not commercially available. Therefore, in order to remove all ambiguity and circularity regarding the charges (for accounting purposes) for the services that Duke Power purchases from or provides to affiliates pursuant to the Utility Service Agreement and the Operating Companies Agreement, CUCA believes and recommended that the Commission order should clearly impose the asymmetric pricing provision restrictions upon each and every transaction involving Duke Power pursuant to these agreements. CUCA stated that such clarifying language is necessary and appropriate given Duke Energy's intention to transfer more than one thousand employees from Duke Power to Duke Services, which indicates numerous and significant affiliate transactions that will be difficult to monitor. In addition, CUCA believes that the independent auditor acting pursuant to Regulatory Condition No. 32 should be directed to review whether the allocation methodologies in the agreements are reasonable and consistent with industry norms.

In its reply comments filed on July 29, 2006, Duke Power stated that CUCA's argument misinterprets the Code of Conduct and ignores Commission precedent that permits the sharing of support services by a service company on a fully distributed cost basis.

Duke Power cited Section III.D.4 of the Code of Conduct, which provides that:

> To the extent that Duke Power, Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from Duke Energy Shared

> Services, these Shared Services may be jointly provided to Duke Power, Duke Energy Corporation, the Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by Duke Power is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to Duke Power and is undertaken pursuant to the provisions of Regulatory Condition No. 18 approved by the Commission in Docket No. E-7, Sub 795. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual(s) filed with the Commission pursuant to Regulatory Condition No. 20, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

According to Duke Power, this language is consistent with the Code of Conduct in effect prior to the merger with Cinergy Corp. Similarly, the Commission-approved Codes of Conduct for Progress Energy Carolinas, Dominion NC Power, and Public Service Company of North Carolina, Inc. provide that a service company may provide the utility and its affiliates with support services "on a joint basis" and that such shared services shall be charged among the entities receiving the services.

Duke Power believes that the issue of shared services being provided on a fully distributed cost basis was addressed at length in the evidentiary hearing in Docket No. E-7, Sub 795. Duke Power argued that its testimony made it clear that the savings estimated to result from the merger between Duke Energy and Cinergy Corp. are predicated on the sharing of corporate and utility support functions on an at-cost basis. Duke Power also noted that Section III.D.3(d) of the Code of Conduct provides an express exception to the asymmetrical pricing rules for certain transactions between Duke Power and its Utility Affiliates. Duke Power added that the Regulatory Conditions and Code of Conduct approved by the Commission provide for the sharing of corporate and utility support functions, subject to the obligation to perform periodic market studies to demonstrate that it is cost-effective to Duke Power for these functions to be performed by the shared services company. Finally, Duke Power submitted that the Commission has already decided the issue raised by CUCA in approving the Regulatory Conditions and Code of Conduct.

CONCLUSIONS

After careful consideration, the Commission concludes that the Utility Service Agreement, the Operating Companies Agreement, the Operating Company/Nonutility Companies Service Agreement and the lists of services Duke Power intends to take or provide under these agreements, as revised and subject to the changes and conditions agreed upon by Duke Power and the Public Staff, should be accepted for filing and that Duke Power should be allowed to make payments under the terms and conditions of these agreements, pursuant to G.S. 62-153 and Regulatory Condition No. 20. The Commission further concludes that the services included in the filed list of services, as revised, which Duke Power intends to take under the Utility Service Agreement constitute Shared Services under the Regulatory Conditions and Code of Conduct. In addition, the Commission concludes that Section D.(5) of the Code of Conduct approved by the Commission Order dated March 24, 2006, in Docket No. E-7, Sub 795 should be amended, as agreed upon and proposed by Duke Power and the Public Staff and as set forth above.

With the additional conditions related to preemption, the Commission is convinced that its jurisdiction is not adversely affected by the service agreements and transfer of function. The taking of services by Duke Power pursuant to these service agreements and lists of services is subject to the requirement that Duke Power be able to demonstrate on an ongoing basis that the transfer of functions and employees and the resulting organization is more beneficial to its North Carolina retail ratepayers (including cost of service impacts) than any other feasible organizational structure.

The service agreements accepted herein and the payments allowed pursuant thereto will remain subject to ongoing review as to the reasonableness of each agreement, the applicable list of services and the amount of compensation paid. The areas subject to review include, but are not limited to: (a) the services taken by Duke Power pursuant to the service agreements; (b) the costs and benefits assigned and/or allocated in connection with such services; (c) the determination and/or calculation of the bases and factors utilized to assign and/or allocate such costs and benefits; and (d) Duke Power's compliance with its Commission-approved Code of Conduct and Regulatory Conditions, as currently approved and revised by the Commission in the future.

With respect to the issue raised by CUCA, the Commission rejects the position of CUCA for the reasons generally stated by Duke Power in its reply comments and further comments. In so doing, the Commission notes that Section III.D.4. in the Commission-approved Code of Conduct provides that Shared Services may be jointly provided to Duke Power provided that such services are cost beneficial on a service-by-service basis. Any challenge to the cost-effectiveness of Duke Power's decision to obtain Shared Services from Duke Services may be advanced and adjudicated in an appropriate general rate case or complaint proceeding.

Finally, Duke Power should incorporate revisions and changes agreed upon by the Public Staff in these service agreements and file executed copies of the agreements. In addition, Duke Power should file one complete list of services incorporating all previously filed revisions for each agreement.

IT IS, THEREFORE, ORDERED as follows:

1. That the Utility Service Agreement, the Operating Companies Agreement, the Operating Company/Nonutility Companies Service Agreement, and the lists of services Duke Power intends to take or provide under these agreements, as revised and including the changes and conditions agreed upon by Duke Power and the Public Staff, are hereby accepted for filing and Duke Power is hereby authorized to make payments under the terms and conditions of these agreements.

2. That the services included in the lists of services, as revised and filed, which Duke Power intends to take under the Utility Service Agreement constitute Shared Services pursuant to the Commission-approved Code of Conduct.

3. That Section D.5 of the Code of Conduct approved by the Commission Order dated March 24, 2006, in Docket No. E-7, Sub 795 is hereby amended, as agreed upon and proposed by Duke Power and the Public Staff, and as set forth hereinabove.

4. That the taking of services by Duke Power pursuant to these service agreements and lists of services shall be subject to the requirement that Duke Power be able to demonstrate on an ongoing basis that the transfer of functions and employees and the resulting organization is more beneficial to North Carolina retail ratepayers, including cost of service impacts, than any other feasible organizational structure.

5. That the service agreements accepted herein by the Commission, and the payments allowed thereunder, shall be subject to ongoing review as to the reasonableness of each agreement, the applicable lists of services and the amount of compensation paid and shall be subject to modification by Commission Order.

6. That Duke Power shall incorporate the revisions and changes agreed upon by the Public Staff in these service agreements and file executed copies of the agreements. In addition, Duke Power shall file one complete list of services incorporating all previously filed revisions for each agreement.

7. That for ratemaking purposes, this Order shall not constitute approval of the amount of fees, or other compensation paid under these agreements, and that the authority granted herein is without prejudice to the right of any party to take issue with any provision of these agreements in a future proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of October, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

mr103006.01

Chair Jo Anne Sanford did not participate in this decision.

DOCKET NO. E-7, SUB 795

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation for	)	ORDER APPROVING MERGER
Authorization under G.S. 62-111 to Enter	)	SUBJECT TO REGULATORY
Into a Business Combination Transaction	)	CONDITIONS AND CODE OF
With Cinergy Corp. and for Approval of	)	CONDUCT
Affiliate Agreements under G.S. 62-153	)	

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, December 6, 2005, at 9:30 a.m., Tuesday, December 13, 2005, at 1:00 p.m., Wednesday, December 14, 2005, at 9:30 a.m., Thursday, December 15, 2005, at 9:30 a.m., and Wednesday, January 18, 2006, at 9:30 a.m.

BEFORE: Chair Jo Anne Sanford, Presiding, and Commissioners Robert V. Owens, Jr., Sam J. Ervin, IV, Lorinzo L. Joyner, James Y. Kerr, II, and Howard N. Lee

APPEARANCES:

For Duke Energy Corporation:

Kodwo Ghartey-Tagoe, Chief Litigation Counsel, Lara S. Nichols, Associate General Counsel, and Lawrence B. Somers, Assistant General Counsel, Duke Energy Corporation, 422 South Church Street, Charlotte, North Carolina 28202

Robert W. Kaylor, Law Offices of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

For Carolina Industrial Group for Fair Utility Rates III:

Ralph McDonald, Bailey & Dixon, LLP, P.O. Box 1351, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc:

James West, West Law Offices, P.C., 434 Fayetteville Street Mall, Suite 1735, Raleigh, North Carolina 27601

For Environmental Defense:

Daniel Whittle, Senior Attorney, Environmental Defense, 2500 Blue Ridge Road, #330, Raleigh, North Carolina 27607

For North Carolina Sustainable Energy Association:

John Runkle, P.O. Box 3793, Chapel Hill, North Carolina 27515

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, and Gisele L. Rankin, Staff Attorney, Public Staff–North Carolina Utilities Commission, 4326 Mail Services 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

BY THE COMMISSION: This matter arose upon the filing of an Application by Duke Energy Corporation (Duke Energy) on July 15, 2005, seeking authority pursuant to G.S. 62-111 to enter into a business combination (hereinafter referred to as "the Merger") with Cinergy Corp. (Cinergy) and approval pursuant to G.S. 62-153 of certain affiliate agreements. Exhibits filed with the Application included the Agreement and Plan of Merger (Merger Agreement) dated May 8, 2005, and amended as of July 11, 2005; a schematic diagram of transactions under the Merger Agreement; Annual Reports of Duke Energy and Cinergy; a Cost-Benefit Analysis; and a Market Power Analysis. Also included were four affiliate agreements: a Utility Service Agreement, an Operating Companies Service Agreement, an Operating Company/Non-Utility Companies Service Agreement, and a Utility Money Pool Agreement. A Tax Sharing Agreement was filed on August 1, 2005. On November 18, 2005, Duke Energy filed the Second Amendment to the Merger Agreement, dated October 3, 2005.

In response to the Application, the Commission issued an order on August 11, 2005, scheduling the matter for hearing on December 6, 2005, and requiring public notice. On November 17, 2005, the Commission issued an order scheduling the December 6 hearing for the sole purpose of receiving public witness testimony and rescheduling the evidentiary hearing for December 13, 2005.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc. (CUCA); Carolina Industrial Group for Fair Utility Rates III (CIGFUR III); North Carolina Sustainable Energy Association, Inc. (NCSEA); Environmental Defense; and the North Carolina Electric Membership Corporation (NCEMC). By various orders, the Commission granted the petitions to intervene. The Attorney General filed notice of intervention pursuant to G.S. 62-20. The intervention of the Public Staff was deemed recognized pursuant to Commission Rule R1-19(e).

On November 29 and 30, 2005, a Stipulation and Agreement (Stipulation) between Duke Energy and the Public Staff was filed by the Public Staff. Attached to the Stipulation were proposed Regulatory Conditions, a proposed Code of Conduct, and a revised exhibit showing the net merger savings proposed to be shared by Duke Energy with its North Carolina retail ratepayers.

The matter came on for hearing as scheduled. Dr. Edwin Cox, a licensed physician and former director of the cancer center database at the Duke Comprehensive Cancer Center, and Martin Lancaster, President of the North Carolina Community College System, testified as public witnesses.

Duke Energy presented the direct testimony of Ruth G. Shaw, President and Chief Executive Officer of Duke Power; James E. Rogers, Chairman and Chief Executive Officer of Cinergy; Myron L. Caldwell, Group Vice President and Chief Financial Officer of Duke Power; Thomas J. Flaherty, Senior Vice President in the Energy and Utilities practice of Booz Allen Hamilton; and Carol E. Shrum, Vice President of Financial Planning and Analysis for Duke Energy Business Services. The testimony of Dr. William Hieronymus, Vice President of CRA International, Inc. (formerly Charles River Associates), filed with the Application, was entered into the record by stipulation.

CIGFUR III presented the testimony of Nicholas Phillips, Jr., a consultant with the firm of Brubaker & Associates, Inc. CUCA presented the testimony of Kevin W. O'Donnell, President of Nova Energy Consultants, Inc. The Public Staff presented the joint testimony of Elise Cox, Assistant Director, Accounting Division; Thomas W. Farmer, Jr., Director, Economic Research Division; and James S. McLawhorn, Utilities Engineer, Electric Division. Environmental Defense presented the testimony of Michael Shore, Senior Air Policy Analyst.

Duke Energy presented the rebuttal testimony of Myron L. Caldwell, Thomas J. Flaherty, and Janice D. Hager, Vice President, Rates and Regulatory Affairs, for Duke Power. CUCA presented the rebuttal testimony of Kevin W. O'Donnell.

By order issued December 20, 2005, the Commission directed Duke Energy and the Public Staff to convene a conference of all parties to discuss and negotiate reasonable and appropriate post-hearing changes and modifications to the proposed Regulatory Conditions and Code of Conduct that were attached to the Stipulation. The parties were directed to prepare and file a matrix of contested, non-settled issues following the negotiations. The order also required Duke Energy to file a pro forma balance sheet setting forth the financial position of Duke Power Company, LLC, immediately following the Merger and updated Cost-Benefit Analyses setting forth the total five-year and ten-year net merger savings expected to be realized from the Merger. The Public Staff was required to file a detailed assessment of the separate settlement proposals filed with or approved by each of the state and federal agencies that are required to rule on the Merger, with particular emphasis on the benefits granted to ratepayers and whether any of those benefits would invoke the provisions of the Most Favored Nation clause in the proposed Regulatory Conditions. Duke Energy was also requested to file copies of all state and federal orders ruling on the proposed Merger. By order issued December 29, 2005, the Commission reaffirmed the requirement of an informal conference and granted Duke Energy and the Public Staff's request for oral argument.

On December 22, 2005, Duke Energy filed copies of the following orders: Order Authorizing Merger issued December 20, 2005, by the Federal Energy Regulatory Commission (FERC) in Docket No. EC05-103-000; Order Approving Stipulations and Merger issued December 7, 2005, and Order Granting Clarification issued December 8, 2005, by the Public Service Commission of South Carolina in Docket No. 2005-210-E; Order issued November 29, 2005, by the Public Service Commission of Kentucky in Case No. 2005-00228; and Finding and Order issued December 21, 2005, by the Public Utilities Commission of Ohio in Case Nos. 05-732-EL-MER, 05-733-EL-AAM, and 05-794-GA-AAM.

On January 13, 2006, Duke Energy filed the pro forma balance sheet and updated Cost-Benefit Analyses required by the Commission.

On January 17, 2006, the Public Staff filed a matrix of contested, non-settled issues and the Revised Regulatory Conditions and Code of Conduct provisions proposed by Duke Energy and the Public Staff, and CUCA filed its proposed Revised Regulatory Conditions and Code of Conduct. An oral argument to consider relevant issues related to the proposed Regulatory Conditions and Code of Conduct was held as scheduled on January 18, 2006.

On January 25, 2006, Environmental Defense and NCSEA jointly filed a Partial Proposed Order.

On January 27, 2006, the Public Staff filed Further Revised Regulatory Conditions and Code of Conduct, a revised matrix of contested, non-settled issues, and its assessment of the settlement proposals and orders in other jurisdictions; the Attorney General filed his Brief; and the Commission issued an Order Granting Second Extension of Time to File Proposed Orders and Briefs.

On January 30, 2006, the Public Staff filed its Proposed Order and Brief, Duke Energy filed its Proposed Order, and Briefs were filed by CUCA and CIGFUR III. On February 1, 2006, CIGFUR III filed redacted pages omitted from its Brief filed on January 30, 2006.

On February 10, 2006, in response to the Commission's order of December 20, 2005, Duke Energy filed a copy of the Nuclear Regulatory Commission's Order Approving Application Regarding Proposed Corporate Restructuring and Approving Conforming Amendments, issued on February 7, 2006.

On February 14, 2006, Duke Energy filed its Revised Utility Money Pool Agreement.

On March 3, 2006, Duke Energy filed its Revised Tax Sharing Agreement and, in response to the Commission's order of December 20, 2005, the Entry on Rehearing issued by the Public Utilities Commission of Ohio on February 6, 2006.

On March 21, 2006, in response to the Commission's order of December 20, 2005, Duke Energy filed a copy of the Indiana Utility Regulatory Commission's March 15, 2006 order approving the Settlement Agreement and items related to the merger of Cinergy and Duke Energy Corporation.

On March 23, 2006, the Public Staff filed an Updated Assessment of Orders wherein it set forth its evaluation of the Indiana Utility Regulatory Commission's recent order approving the Settlement Agreement.

Based on the foregoing, the evidence presented at the hearing, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT

1. Duke Energy is a corporation duly organized and existing under the laws of North Carolina and headquartered in Charlotte, North Carolina. Duke Power, a division of Duke Energy, is engaged in the business of generating, transmitting, distributing, and selling electricity to approximately 2.2 million retail customers in a service area that covers central and western North Carolina and western South Carolina.

2. Duke Energy owns and operates approximately 94,000 miles of distribution lines and 13,000 miles of transmission lines. It also sells electricity at wholesale to municipal, cooperative, and investor-owned electric utilities.

3. Duke Energy is a public utility subject to the jurisdiction of this Commission and the jurisdiction of the Public Service Commission of South Carolina. Duke Energy is also a public utility under the Federal Power Act (FPA) and is subject to the jurisdiction of the FERC.

4. Subsidiaries of Duke Energy are engaged in a broad range of energy and energy-related business activities in North and South America.

5. Cinergy is a corporation duly organized and existing under the laws of Delaware and headquartered in Cincinnati, Ohio. Its principal direct and indirect subsidiaries are PSI Energy, Inc. (PSI), a vertically-integrated electric utility serving a portion of Indiana; The Cincinnati Gas & Electric Company (CG&E), a utility engaged in the production, transmission, distribution, and sale of electricity and the transportation of natural gas in southwestern Ohio; and The Union Light, Heat and Power Company (ULH&P), a wholly-owned subsidiary of CG&E and a vertically-integrated utility providing retail electric and natural gas service in northern Kentucky. Collectively, PSI, CG&E, and ULH&P serve approximately 1.5 million retail electric customers and 500,000 retail natural gas customers. Cinergy is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA 1935).

6. PSI is a public utility subject to the jurisdiction of the Indiana Utility Regulatory Commission, and ULH&P is a public utility subject to the jurisdiction of the Public Service Commission of Kentucky. The electric transmission and distribution functions and natural gas distribution functions of CG&E are subject to the jurisdiction of the Public Utilities Commission of Ohio. PSI, ULH&P, and CG&E are public utilities under the FPA and are subject to the jurisdiction of the FERC.

7. Subsidiaries of Cinergy are involved in wholesale power generation, energy marketing and trading, and other energy-related businesses.

8. Duke Energy is lawfully before the Commission pursuant to G.S. 62-111 and 62-153 with respect to the relief sought in its Application and is in compliance with the filing requirements established by the Order Requiring Filing of Analyses issued November 2, 2000, in Docket No. M-100, Sub 129, with respect to the Market Power and Cost-Benefit Analyses submitted with the Application.

9. The Merger Agreement provides that, through a series of mergers, conversions, and reorganizations, Duke Power, Duke Capital, LLC, Duke Energy Shared Services, LLC, and Cinergy will become wholly-owned subsidiaries of a new Delaware holding company to be named Duke Energy Corporation (sometimes referred to as "new Duke Energy").[1] The Merger will be accomplished through an all-stock transaction. Holders of Duke Energy common stock will receive new Duke Energy common stock on a one-for-one basis, and holders of Cinergy common stock will receive 1.56 shares of new Duke Energy common stock for each share of Cinergy stock held. After

[1] For purposes of this order, the term "Duke Energy" will be used to refer to existing Duke Energy Corporation and to new Duke Energy Corporation, as appropriate.

the Merger is completed, former Duke Energy shareholders will own approximately 76% and former Cinergy shareholders will own approximately 24% of the new Duke Energy holding company stock.

10. Pursuant to the Merger Agreement, Duke Energy will convert to a limited liability company to be called Duke Power Company, LLC (Duke Power), and Duke Power then will distribute its assets and liabilities associated with Duke Capital to new Duke Energy. Following the Merger, Duke Power will be a stand-alone public utility without extensive non-utility holdings.

11. Known and potential benefits of the Merger to Duke Energy include greater diversity and depth of resources, diversity of service areas, increased efficiency, and increased financial strength and flexibility. Known and potential benefits to North Carolina ratepayers in particular include economies of scale and scope that will enable Duke Power to offer lower rates than otherwise would have been possible, greater depth and diversity of human resources experience that will help Duke Power to continue its commitment to customer service, and access to best practices of other utilities in the Cinergy group.

12. Another significant, known and potential benefit of the Merger to ratepayers is the creation of a holding company, which will allow Duke Power to be maintained as a separate legal entity with its own debt issuances and its own capital structure and will also simplify the tracking of costs and revenues between utility and non-utility operations.

13. The primary quantifiable benefit of the Merger to ratepayers consists of the estimated net merger savings generated by combining certain corporate and utility functions after the Merger. Duke Power proposes to share 42% ($117,517,000) of the five-year estimated net merger savings amount of $279,841,000 assignable to its North Carolina retail customers. Pursuant to Finding of Fact No. 35, Duke Power will be required to implement a one-year across-the-board decrement to rates for the benefit of its North Carolina retail customers in the amount of $117,517,000. The Commission makes no specific determination as to the reasonableness of Duke Energy's five-year estimated net merger savings amount of $279,841,000 assignable to its North Carolina retail customers, the propriety of the determination and apportionment thereof, or the validity and correctness of the Company's Cost-Benefit Analyses.

14. Known and potential costs and risks of the Merger to ratepayers include the possibility of preemption resulting from the creation of a holding company, the repeal of PUHCA 1935, and the enactment of the Energy Policy Act of 2005 (EPACT 2005). Other known and potential costs and risks include cost increases that could impact North Carolina retail rates, potential adverse impacts on Duke Power's cost of capital, potential adverse effects on Duke Power of transactions within the holding company family and the resulting need for increased regulatory oversight of such transactions, the potential for Duke Power to unreasonably favor its unregulated affiliates over non-affiliated suppliers of goods and services, the potential for Duke Power's quality of service to deteriorate because of increased management focus on diversification and growth, and the exposure of Duke Power's ratepayers to environmental compliance costs incurred by Cinergy subsidiaries. The Commission-approved Regulatory Conditions and Code of Conduct will protect Duke Power's North Carolina retail ratepayers to the extent reasonably possible from known and potential costs and risks of the Merger.

15. The Commission-approved Regulatory Conditions will effectively protect the Commission's jurisdiction from the probability of federal preemption.

16. The Commission-approved Regulatory Conditions will effectively address known and potential risks and concerns related to cost allocation and ratemaking arising from the Merger.

17. The Commission-approved Regulatory Conditions will impose appropriate and effective auditing and reporting requirements with respect to affiliate transactions and cost of service.

18. The Commission-approved Regulatory Conditions will effectively protect Duke Power's North Carolina retail customers from impacts of the Merger on cost of service for ratemaking purposes.

19. The Code of Conduct required by the Commission-approved Regulatory Conditions will effectively govern the relationships, activities, and transactions among Duke Power and other members of the Duke Energy holding company family following the Merger.

20. The Commission-approved Regulatory Conditions will effectively address known and potential risks and concerns related to finance and corporate governance issues arising from the Merger.

21. The Commission-approved Regulatory Conditions will effectively enable the Commission to exercise its jurisdiction over business combinations involving Duke Power or other members of the Duke Energy holding company family following the Merger.

22. The Commission-approved Regulatory Conditions will effectively address known and potential risks and concerns related to structure and organization arising from the Merger.

23. The Commission-approved Regulatory Conditions will provide appropriate and effective procedures for advance notices and other filings arising from the Merger.

24. The Commission-approved Regulatory Conditions will effectively ensure that Duke Energy and Duke Power maintain a commitment to customer service following the Merger.

25. The Commission-approved Regulatory Conditions will effectively ensure that Duke Power's North Carolina retail customers are protected from any adverse effects of a tax sharing agreement and receive an appropriate portion of income tax benefits associated with Duke Energy Shared Services.

26. The Commission-approved Regulatory Conditions will effectively preserve the benefits of Nantahala's historical hydroelectric resources and cost of service for Duke Power's Nantahala retail customers following the Merger.

27. The Commission-approved Regulatory Conditions will effectively ensure that the Commission and the Public Staff continue to have access to the books and records of Duke Power and members of the Duke Energy holding company family in accordance with North Carolina law following the Merger.

28. The Commission-approved Regulatory Conditions will appropriately recognize the continuing effect of prior Commission orders.

29. The Commission-approved Regulatory Conditions accurately describe their effect on the Commission's statutory authority and Duke Energy's rights under state and federal law.

30. The Commission-approved Regulatory Conditions do not impose legal obligations on entities in which Duke Energy does not have a controlling interest.

31. The Commission-approved Regulatory Conditions will appropriately allow requests for waivers of any aspect of the conditions under exigent circumstances.

32. The Commission-approved Regulatory Conditions will appropriately become effective only upon closing of the Merger.

33. The Commission-approved Regulatory Conditions will appropriately recognize the rights of parties to this docket with respect to participation in subsequent proceedings.

34. The Merger presents no known risk of adverse competitive effects within the jurisdiction of the Commission or concerns of increased market power within Duke Power's service territory.

35. Duke Power shall implement a one-year across-the-board decrement to rates for the benefit of its North Carolina retail customers in the amount of $117,517,000. In addition, any fuel-related savings associated with the Merger shall be flowed through to Duke Power's North Carolina retail customers pursuant to G.S. 62-133.2.

36. Duke Power shall contribute $12,000,000 to various energy- and environmental-related and economic- and educationally-beneficial programs, said funds to be distributed as follows: $6,000,000 to Duke Power's Share the Warmth, Cooling Assistance, and Fan-Heat Relief programs; $2,000,000 for conservation and energy efficiency programs; $2,000,000 to the Community College Grant Fund; and $2,000,000 to NC GreenPower.

37. The Commission will, in 2007, initiate an investigation pursuant to G.S. 62-130(d), 62-133, and 62-136(a) to determine whether Duke Power's existing rates and charges are unjust and unreasonable and, as part of this investigation, will require Duke Power to either (a) file a general rate case (including prefiled testimony and exhibits) in North Carolina pursuant to G.S. 62-137 or (b) show cause in the form of prefiled testimony and exhibits why the Company's existing rates and charges should not be found unjust and unreasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 – 8

The evidence supporting these findings of fact is contained in the verified Application and in the testimony of Duke Energy witnesses Shaw and Rogers. These findings are essentially informational, procedural, and jurisdictional in nature and for the most part are not in dispute.

Pursuant to the order entered on November 2, 2000, in Docket No. M-100, Sub 129, applicants for merger approval pursuant to G.S. 62-111 are required, among other things, to file (1) a market power analysis employing the Herfindahl-Hirschman Index or other accepted measurement and (2) sensitivity analyses on the impact on market power of significant factors as discussed in that order. Applicants are also required to file a "comprehensive list of all material areas of expected benefit, detriment, cost, and savings over a specified period (e.g., three to five years) following consummation of the merger." The purpose of such analyses is to assist the Commission in determining whether or not a merger meets the statutory standard for approval. None of the parties in this case challenged the Market Power Analysis submitted with the Application or contended that the Merger raises market power issues. With respect to the Cost-Benefit Analysis, at the hearing some questioned the allocation of net merger savings and the proposed sharing mechanism as discussed below, but none took issue with the estimates themselves.

The Commission therefore finds and concludes that Duke Energy is lawfully before the Commission with respect to the relief sought in its Application and has fully met the merger filing requirements established in Docket No. M-100, Sub 129.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 AND 10

The evidence supporting these findings of fact is contained in the verified Application, including the Merger Agreement, and the testimony of Duke Energy witness Caldwell. These findings are essentially uncontroverted.

Through its Application and the testimony of witness Caldwell, Duke Energy described the mergers, conversions, and restructurings through which the Merger will be accomplished, including the creation of a new holding company to be named Duke Energy Corporation (new Duke Energy), and the conversion of the current Duke Energy Corporation into a limited liability company, Duke Power Company, LLC. Witness Caldwell testified that post-merger, Duke Power will be a separate, first-tier subsidiary under new Duke Energy. He further explained that, as part of the overall merger transaction, Duke Power will distribute its ownership of Duke Capital to new Duke Energy and become a free-standing utility subsidiary without extensive non-utility holdings other than land held for future use.

Thus, following the Merger, Duke Power will be a stand-alone public utility without extensive non-utility holdings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the verified Application and the testimony of Duke Energy witnesses Shaw, Rogers, and Flaherty.

Duke Energy witness Shaw testified that the Merger will benefit Duke Energy and its customers by creating greater diversity and depth of resources, as well as increasing the number and diversity of service areas and customers. She stated that the integration of the two companies will lead to increased efficiency and lower operating costs and increase the financial flexibility of the new company. Witness Shaw further testified that the Merger will allow the companies to reduce risk to regulated operations by adding diversity of service areas, climates, and economic and competitive conditions. Referring to witness Flaherty's testimony, she stated that the Merger will result in synergies that will lower the overall cost structure of the combined company and enable Duke Power to offer lower rates than would otherwise have been possible. She also stated that the Merger will enhance Duke Power's ability to serve its customers by providing greater depth and diversity of human resources experience and by allowing access to "best practices" among the operating companies.

Duke Energy witness Rogers testified that the anticipated cost savings and synergies, paired with the increased scale and scope of the combined company, will position new Duke Energy to serve its customers well in an era of rising costs.

Based on the conclusions reached hereinafter with respect to the effectiveness of the Commission-approved Regulatory Conditions, the Commission finds and concludes that known and potential benefits to North Carolina retail ratepayers in particular include economies of scale and scope that will enable Duke Power to offer lower rates than otherwise would have been possible, greater depth and diversity of human resources experience that will help Duke Power to continue its commitment to customer service, and access to best practices of other utilities in the Cinergy group.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witnesses Caldwell, Shrum, and Hager.

Duke Energy witness Caldwell testified that Duke Power will remain responsible for approximately $6 billion of debt securities issued at the Duke Energy level for which it is responsible today. These securities consist of approximately $4.5 billion of unsecured debt and $1.5 billion of first mortgage bonds.

He explained that the unsecured debt was issued for the benefit of Duke Power for the purpose of supporting its regulated operations and can only be used to support the electric operations within Duke Power, but, because Duke Power is a division of Duke Energy, this debt was issued in the legal name of Duke Energy. By virtue of the conversion of the existing Duke Energy into Duke Power, the holders of the securities would not have the ability to call on the assets of Duke Capital in the future, unless Duke Energy guaranteed them. As a result, new Duke Energy will guarantee the unsecured debt to maintain the current status of the debt holders and their ability to call on the assets of new Duke Energy, including Duke Capital. He further explained that Duke Power does not own or have financial encumbrances associated with Duke Capital operations.

Witness Caldwell testified that, as a separate subsidiary, Duke Power's credit risk will be rated separately from that of new Duke Energy and its other subsidiaries. The structure in place after the Merger will potentially improve the credit standing of Duke Power as a stand-alone company, as it will give Duke Power visibility and transparency for the rating agencies. Witness Caldwell further testified that each operating company, including Duke Power, will have its own distinct capital structure for both accounting and ratemaking purposes. Duke Power will issue its own debt and/or receive equity contributions from new Duke Energy as needed. Thus, the formation of the holding company and the presence of Duke Power as a stand-alone subsidiary will provide additional protection to insulate Duke Power from any potential risks associated with the unregulated businesses.

The Commission recognizes that the holding company is a common and accepted corporate structure for diversified business activities. Indeed, the Commission has considerable experience with this structure, having approved regulatory conditions, codes of conduct, cost allocation manuals, and a variety of affiliate agreements for the Carolina Power & Light Company, Dominion Resources, and SCANA holding companies. Moreover, as Duke Energy witnesses Shrum and Hager observed, the use of a service company is not a new concept to Duke Power or the Commission, inasmuch as many service company functions are currently being provided by Duke Energy Business Services (DEBS). Thus, while the number of transactions may increase, the costs will either be directly assigned or allocated in accordance with the cost allocation manual (CAM) just as they are today. There is no reason to conclude that the allocation process will be any more complex or that affiliate transactions will not be appropriately documented, reported, and audited as currently required. Contrary to the contentions of CIGFUR III and CUCA, the Commission believes that a holding company structure can actually simplify the tracking of costs and revenues between utility and non-utility operations, which can be expected to result in improved regulatory oversight, particularly with the Commission-approved Regulatory Conditions.

Furthermore, the Commission agrees with Duke Energy witness Caldwell that this structure should potentially improve Duke Power's credit standing, as Duke Power should be insulated from events that occur elsewhere in the holding company family. As discussed below, the Commission also concludes that with the "ring fencing" provisions of the approved Regulatory Conditions, Duke Power should be protected from any adverse affects that might result from its membership in a holding company system.

Based on the conclusions reached hereinafter with respect to the effectiveness of the Commission-approved Regulatory Conditions, the Commission finds and concludes that Duke Power's North Carolina retail ratepayers will benefit from the creation of a holding company as part of the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the verified Application, the testimony of Duke Energy witnesses Flaherty, Shrum, and Hager, the testimony of CIGFUR III witness Phillips, and the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

Duke Energy witness Flaherty testified that the Merger is expected to provide the potential for an estimated \$2.1 billion in total gross cost savings to be realized for corporate, shared services, regulated, and non-regulated businesses over a five-year period following the close of the Merger. Witness Flaherty testified that \$780 million of the total related to gross cost savings were directly attributable to the non-regulated business segment, whereas approximately \$1.3 billion of gross savings were attributable to corporate, shared services, and utility-related services. He also stated that approximately \$770 million in corporate, shared services, regulated, and non-regulated costs-to-achieve, and other offsets to the identified savings, had been estimated. These offsets consist of (1) approximately \$61 million directly attributable to the non-regulated segment, (2) approximately \$183 million in change-in-control payments that have been eliminated from consideration for purposes of calculating net merger savings for this proceeding, (3) approximately \$513 million of costs-to-achieve related to corporate, shared services and utility segments, and (4) \$10 million in pre-merger initiatives for cost savings that Cinergy had planned prior to the Merger.

Witness Flaherty testified that the net merger savings that relate to corporate, shared services, and the utility segments amount to approximately \$807 million (\$1.3 billion in gross savings less \$513 million in costs-to-achieve and \$10 million in pre-merger initiatives). He stated that the \$1.3 billion in cost savings are in six major categories: corporate and headquarters staffing, utility support staffing, corporate and administrative programs, information technology, supply chain, and coal supply. He also stated that the \$513 million in costs-to-achieve are in the following categories:

separation, retention, relocation, directors' and officers' coverage, regulatory process, internal and external communication, transition costs, and transaction costs.

Witness Flaherty testified that the estimated cost savings were jointly developed by the management of Duke Energy and Cinergy with the assistance of Booz Allen Hamilton. According to witness Flaherty, the process utilized by Duke Energy and Cinergy was comprehensive and captured all significant sources of merger-related costs savings that are typically available.

Duke Energy witness Shrum testified that the estimated net savings were allocated to Duke Power and other companies of new Duke Energy using cost causation principles. For example, savings related to customer service were assigned using the number-of-customers ratio. When costs/savings could not be identified at the function level or data necessary for the calculation of a proposed new factor could not yet be identified, a general allocation method was used to assign costs/savings.

The Public Staff witnesses testified that estimated five-year net savings assignable to North Carolina retail customers should be $279,841,000, which is an increase from the $273,283,000 amount originally filed by Duke Power. The increase is attributable to changes in an affiliate allocation factor and a jurisdictional allocation factor assigning net savings to North Carolina retail operations. As shown on Attachment C of the Stipulation, Duke Energy and the Public Staff agreed that the amount of estimated five-year net savings assignable to North Carolina retail customers is $279,841,000.

Duke Energy witness Hager testified that the vast majority of the non-regulated savings were due to the consolidation of two trading floors to one trading floor for the Duke Energy North America (DENA) operations. She testified that, now that Duke Energy is divesting itself of the majority of its merchant generation and is no longer going to have a trading floor, those savings are no longer merger savings but are savings associated with discontinued operations.

CIGFUR III witness Phillips disagreed with the presentation or allocation of the net merger savings in Table 1 of witness Flaherty's testimony. Witness Phillips testified that the way the savings are structured, Duke Energy will keep the total unregulated savings, which he stated is more than 50% of the total, and Duke Energy will share 42% of the smaller regulated savings. According to witness Phillips' calculation, under this structure, Duke Energy will keep 84% of the total savings and will give only 16% of the total savings to regulated ratepayers.

The Commission, in conjunction with its ruling on Finding of Fact No. 35, concludes that Duke Power should be required to implement a one-year across-the-board decrement to rates for the benefit of its North Carolina retail customers in the amount of $117,517,000. The Commission makes no specific finding or determination as to the reasonableness of Duke Energy's five-year estimated net merger savings amount of $279,841,000 assignable to its North Carolina retail customers, the propriety of the determination and apportionment thereof, or the validity and correctness of the Company's Cost-Benefit Analyses. Such a determination is unnecessary in view of the Commission's decision to accept Duke's offer to refund the amount of $117,517,000 to the Company's North Carolina retail customers in a manner to be determined by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn, CIGFUR III witness Phillips, CUCA witness O'Donnell, and Environmental Defense witness Shore.

The Public Staff witnesses testified that, because PUHCA 1935 has been repealed, the concerns about preemption by the Securities and Exchange Commission (SEC) that were addressed in earlier merger proceedings are no longer at issue. The witnesses further testified that they had been advised by counsel that the Merger creates other preemption risks and concerns given the enactment of various other parts of EPACT 2005, including the Public Utility Holding Company Act of 2005 (PUHCA 2005). In addition, they testified that they had been advised by counsel that the repeal of PUHCA 1935 removes a number of significant consumer protections on large holding company systems, such as limitations on non-utility diversification and investment in merchant and foreign generating plants.

The other potential costs and risks identified by the Public Staff include: (1) direct merger costs, indirect corporate costs, and other cost increases that could impact North Carolina retail rates, (2) potential adverse effects on Duke Power's cost of capital, (3) potential adverse effects resulting from transactions between and among Duke Power and its affiliates, (4) the potential for Duke Power to unreasonably favor its unregulated affiliates over non-affiliated suppliers of goods and services, and (5) the potential for Duke Power's quality of service to deteriorate for reasons such as an increased focus on diversification and growth in non-regulated businesses. The Public Staff further testified that all of these concerns have been addressed in the Regulatory Conditions and Code of Conduct stipulated to by the Public Staff and Duke Energy.

CIGFUR III witness Phillips suggested that the proposed Merger presents even greater regulatory challenges than those faced by the Commission in Docket No. E-7, Sub 694. In that case, Duke Power proposed to transfer employees who operate and maintain Duke Power's fossil, hydroelectric, and nuclear generating facilities to subsidiaries of a new affiliate, Duke Energy Generation Services, LLC (DEGS), which would then operate the facilities for Duke Power pursuant to affiliate agreements but would also perform services for an unregulated affiliate, DENA. CUCA witness O'Donnell also cited the DEGS case, noting that the Commission approved the proposed affiliate agreements subject to a number of conditions related to affiliate transactions and that Duke Power ultimately withdrew its request for approval.

The Commission notes that, while some of the conditions imposed in Docket No. E-7, Sub 694 were vacated after the request was withdrawn, most were retained and have been implemented without undue difficulty or fanfare. Moreover, those conditions have been incorporated into the Regulatory Conditions approved in this case. The Commission further notes that one of the principal concerns in the DEGS case was not the complexity of the transactions but the fact that operating personnel were involved. There is no such proposal before the Commission in this case. Indeed, Duke Energy witness Shrum indicated that the utility shared services would be of a different nature and would include managerial support and other administrative-type services. Duke Power's generating facilities will continue to be operated by Duke Power employees as they are today.

Environmental Defense witness Shore testified with respect to financial risks due to future regulation of global warming pollution, especially the costs that Cinergy may be required to bear in order to meet federal standards. Witness Shore recommended that the Commission require an assessment of the financial risks of the transaction. He encouraged the Commission to consider requiring that all new electric generating resources acquired by Duke Energy be selected based on an imputed carbon dioxide cost. He further requested the Commission to consider ordering commencement of a new proceeding to evaluate opportunities for Duke Energy to develop a comprehensive global warming management plan to protect North Carolina ratepayers from the financial risks of future global warming reduction regulation.

Duke Energy witness Hager testified that witness Shore's recommendations are outside the scope of this proceeding. She added that Duke Energy looks forward to the opportunity to work with Environmental Defense and other stakeholders on these issues in the appropriate forums. The Commission agrees that such environmental issues are outside the scope of this specific merger docket. The Commission does note, however, that Commission-approved Regulatory Condition No. 30 holds Duke Power's North Carolina retail customers harmless from all current and prospective liabilities of Cinergy Corp. and its subsidiaries including matters such as, but not limited to, litigation involving manufactured gas plant sites, asbestos claims, and environmental compliance.

Based on the conclusions reached hereinafter with respect to the effectiveness of the Commission-approved Regulatory Conditions, the Commission finds and concludes that Duke Power's North Carolina retail ratepayers will be protected to the extent reasonably possible from known and potential costs and risks of the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witness Caldwell and Public Staff witnesses Cox, Farmer, and McLawhorn.

Duke Energy witness Caldwell testified that EPACT 2005 repealed PUHCA 1935 effective six months from August 8, 2005. He further testified that, as a result, the SEC will no longer have regulatory authority over a public utility holding company system like the proposed Duke Energy system and that the companies do not intend to file for SEC approval of the Merger under PUHCA 1935. Nevertheless, new Duke Energy will be organized as a holding company and will have a services company, a money pool agreement, a tax sharing agreement, and several other structures that enable a more efficient and transparent operation – even though such arrangements are no longer required by federal law.

The Public Staff panel testified that, because PUHCA 1935 has been repealed, the concerns about preemption by the SEC that were addressed in earlier merger proceedings are no longer at issue. They further testified, however, that they had been advised by counsel that the proposed Merger creates other preemption risks and concerns given the enactment of various other parts of EPACT 2005, including PUHCA 2005.

The Public Staff panel further testified that Regulatory Condition Nos. 1 through 15 are designed to protect the Commission's authority from the risk of preemption with respect to affiliate transactions, wholesale contracts, resource adequacy, asset transfers and any proposed transfers of operational control of generating or transmission facilities, and financings.[1] They testified that they

[1] The only conditions currently applicable to Duke Energy in North Carolina related to preemption are Condition (h) approved in Docket No. E-7, Sub 700, and Condition (q) in Docket No. E-7, Sub 596. These conditions

had been advised by counsel that these conditions are intended to address preemption concerns, including those raised by EPACT 2005, and that these conditions adequately protect the Commission's jurisdiction. The only exception to the protection from preemption is the right Duke Power has under Regulatory Condition No. 21 to exercise a limited opportunity under Section 1275(b) of PUHCA 2005 to request that the FERC review traditional service company costs and allocations under certain circumstances.

To address the fact that the FERC had not yet issued its order ruling on Duke Energy's and Cinergy's Merger Application, the Public Staff witnesses further testified that Regulatory Condition No. 16 provides that Duke Energy and the Public Staff will request that the Commission include a paragraph in any order approving the Merger that requires the Public Staff and Duke Power to meet promptly after the FERC issues its order to determine whether changes are needed in the conditions to maintain their intended protections.

Finally, the Public Staff panel testified that Regulatory Condition No. 17, as originally proposed by Duke Energy and the Public Staff, requires Duke Power to provide to the Public Staff on a quarterly basis a list and summary of (1) filings and submissions Duke Power and its affiliates make to the FERC and (2) orders issued by the FERC that are reasonably likely to have an effect on Duke Power's rates or service. The purpose of this condition is to ensure that the Public Staff will be aware of relevant filings and orders so that it can monitor them. This condition was revised after the hearing during the required negotiation process to require Duke Power to file the lists and summaries, but not to serve them.

No other witness filed testimony with respect to these conditions, although CUCA, through its revised conditions filed on January 17, 2006, proposed that a number of revisions be made to them. Most of the proposed revisions with respect to the anti-preemption conditions, however, are not challenges to the anti-preemption conditions themselves, but rather are directed at incorporating CUCA's proposed definitions of "Effect" and "Requesting Intervenor" and at amending Regulatory Condition No. 2 to subject new Duke Energy to G.S. 62-111 and securities regulation by the Commission. These and the other revisions proposed by CUCA will be addressed subsequently.

The Merger raises a number of issues with respect to potential preemption risks that are predominantly legal, rather than factual, in nature. The Commission has been faced with similar issues in prior cases, although they involved the potential for preemption by the SEC under PUHCA 1935. The Commission concluded in those proceedings that a utility becoming part of a registered holding company system created substantial risks that an appellate court would find that the Commission's jurisdiction was preempted, and the Commission therefore imposed a number of conditions designed to protect its jurisdiction in that regard.[1] Because PUHCA 1935 has now been repealed, the SEC's authority is no longer an issue. The risks of preemption created by the Merger

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simply provide that, if Duke Energy or its affiliates engage in acquisitions or other actions that create the possibility of Duke Energy becoming a registered holding company, Duke Energy will notify the Commission, will bear the full risk of any preemptive effects of the FPA or the PUHCA 1935, and will take all such actions as the Commission finds necessary and appropriate to hold North Carolina retail ratepayers harmless from such preemption.

[1] See, e.g., Order Approving Merger and Issuance of Securities, 98 NCUC 187 (Docket No. E-2, Sub 760, August 22, 2000); Order Approving Application, 98 NCUC 259 (Docket No. E-2, Sub 753, May 17, 2000); Order Approving Merger and Issuance of Securities, 97 NCUC 384 (Docket No. G-5, Sub 400, December 7, 1999; Order Approving Merger and Issuance of Securities, 97 NCUC 306 (Docket No. E-22, Sub 380, October 18, 1999).

now must be analyzed with respect to the authority of the FERC given the repeal of PUHCA 1935 and the additional grants of authority to the FERC under EPACT 2005.

The issues related to preemption risks under the FPA can be divided into the following four categories: (1) inter-affiliate transactions involving wholesale sales and the transmission of electricity in interstate commerce under the FPA, (2) inter-affiliate financings, (3) mergers and acquisitions under § 203 of the FPA, including amendments by EPACT 2005, and (4) inter-affiliate transactions involving non-power goods and services under PUHCA 2005. These four categories of issues are discussed separately below.

(1) Wholesale Sales and Transmission in Interstate Commerce

With regard to preemption issues raised by the creation of a holding company and its acquisition of one or more additional public utilities, the Commission dealt with such issues in the Carolina Power & Light Company/Florida Progress merger proceeding (Docket No. E-2, Sub 760) and in the native load priority cases (e.g., Docket Nos. E-100, Sub 85A, and E-2, Sub 820). These issues include: (a) wholesale sales of electricity generally; (b) market-based rates; (c) joint planning, coordination, and generation dispatch (i.e., a holding company system integration agreement); (d) native load priority; (e) Regional Transmission Organization (RTO) membership; and (f) FERC filings, such as Duke's Application to amend its Open Access Transmission Tariff (OATT) to include an Independent Entity and Independent Monitor (Docket No. ER05-1236-000) and the Duke/Cinergy FERC Merger Application (Docket No. EC05-103-000).

The majority of these issues were dealt with in the Stipulation filed by Duke Energy and the Public Staff by adapting conditions that had previously been approved by the Commission in other dockets. The remaining issues were handled by formulating new conditions or, in the case of Cinergy's ownership of a public utility (CG&E) that is subject to retail competition, by changes in other conditions (see, e.g., the definition of "Utility Affiliates" and Regulatory Condition No. 48) and by specific provisions in the Code of Conduct (see, e.g., the definition of "Utility Affiliates" and Sections III.D.3.(d) and III.D.5).

(a) Wholesale Sales Generally. In Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986) (Nantahala), and in Mississippi Power & Light v. Mississippi ex rel. Moore, 487 U.S. 354 (1988) (Mississippi Power), the Supreme Court reasoned that the FERC's approval of an inter-affiliate power sale agreement under § 205 of the FPA was the equivalent of a FERC order requiring the utility to buy the specified amount of power. Because the relevant state commissions, for ratemaking purposes, then treated the utility buyer as having the freedom to buy a different amount, the state decisions resulted in "trapped costs" and were preempted. The key fact in both Nantahala and Mississippi Power was that the purchasing utility's actions were ordered by the FERC either with respect to mandated allocations of power or the rate paid. Because the utility had no choice but to follow the FERC's decision, the Supreme Court reasoned that a state could not then treat the utility as if it were free to make a different purchase or pay a different rate. Nantahala, at pp. 966-67.

When a FERC-imposed obligation to make a specific purchase has not been involved, states have not been found to be preempted from making ratemaking adjustments to disallow imprudent choices among wholesale suppliers. Kentucky West Virginia Gas Co. v. Pennsylvania Public Utilities Commission, 837 F.2d 600 (3d Cir. 1988) (citing the "long-standing notion that a State Commission may legitimately inquire into whether the retailer prudently chose to pay the FERC-approved wholesale rate of one source, as opposed to the lower rate of another source"); Pike County Light & Power Co. v. Pennsylvania Public Utilities Commission, 465 A.2d 735 (1983) (similar holding). In both of these cases, no trapped costs and no preemption were found because the buying utility was free to choose its seller and the state commission's disallowance was based on its judgment as to the wisdom of that choice. Thus, to protect the Commission's jurisdiction from preemption after the Merger, a condition must be imposed to ensure that contracts entered into by Duke Power for the purchase of electricity from affiliates are voluntary and do not obligate Duke Power to make any purchases. Regulatory Condition No. 1 explicitly requires this.

Regulatory Condition No. 1 prescribes procedures related to all contracts between Duke Power and any affiliate and between any affiliates of Duke Power if such contracts are reasonably likely to have an Effect on Duke Power's Rates or Service (as defined in the conditions). First, Duke Power must obtain the Commission's permission before engaging in such inter-affiliate transactions. Second, the contracts themselves must provide that Duke Power's participation in the agreement is voluntary, that Duke Power is not obligated to take or provide services or make any purchases or sales pursuant to the agreement, and that Duke Power may elect to discontinue its participation in the agreement at its election after giving any required notice. Third, the contracts must provide that Duke Power may not (a) make or incur a charge under the contract except in accordance with North Carolina law, or (b) seek to reflect in rates any cost incurred or revenue earned under the contract except as permitted by the Commission.

As a result of Regulatory Condition No. 1, Duke Power's obligation to make purchases pursuant to the inter-affiliate contract would be voluntary, and its obligation to pay charges under the contract would be limited to those charges determined by the Commission to be consistent with Duke Power's obligation under state law to charge just and reasonable rates. This approach responds directly to the "trapped cost" reasoning used in the Supreme Court decisions discussed above. If the FERC-jurisdictional contract (the "filed rate") itself provides that Duke Power's participation is voluntary and limits Duke Power's obligation to one that is consistent with state law and the amount allowed into rates, there can be no "trapped costs" and, therefore, no preemption.

Subsection (c) of Regulatory Condition No. 1 provides a mechanism for enforcing the foregoing by requiring Duke Power to file with the Commission any proposed affiliate contract or amendment 30 days prior to filing it with the FERC. This allows parties and the Commission an opportunity to determine if a proposed contract poses a risk of preemption and provides a process for handling objections.

Regulatory Condition No. 7 serves a number of purposes. Subsection (d) prohibits Duke Power from making a variety of constitutional arguments that could otherwise inhibit the Commission's authority with respect to wholesale contracts in which Duke Power is the seller. The first sentence of Regulatory Condition No. 7(d)(iv) is designed to protect the Commission's jurisdiction to make retail ratemaking decisions involving Duke Power's wholesale contracts from claims of federal preemption based upon the Commerce Clause. The second sentence of Regulatory Condition No. 7(d)(iv) creates an exception that allows Duke to claim "that a specific exercise of authority by the Commission violates the Commerce Clause." At the January 18, 2006 oral argument in this docket, Duke and the Public Staff expressed different views as to the scope of Regulatory Condition No. 7(d)(iv). Duke stated that the exception would apply anytime "you had a Duke-specific case and you looked at a specific transaction and issued an order...." The Public Staff stated that the exception would only apply to a Commission order "that bore no relationship to the facts or evidence...it was irrational, capricious...it was a pretty egregious action." CUCA argues in its brief that the exception in the second sentence is too broad and should be eliminated altogether.

The Commission notes that Progress Energy Carolinas, Inc. (Progress), has a similar regulatory condition and that Progress' condition was discussed before the Commission at an August 30, 2004 conference in Docket No. E-2, Sub 844. At that conference, Progress and the Public Staff "stated that their intent was to bar Commerce Clause challenges globally and only allow them based on specific evidence of undue interference. Progress and the Public Staff agreed that 'what could not be done under this thing would be to say that any condition, period, constituted an implicit Commerce Clause violation, but that instead a showing would have to be made of...undue interference with interstate commerce on a case-by-case basis on the facts of that specific case.'" Order Revising Regulatory Conditions and Code of Conduct (Docket No. E-2, Sub 844, September 15, 2004). The Commission adopted this interpretation of the Progress condition and concluded that the Progress condition put the Commission in a position to protect retail ratepayers. "The primary tool for protecting ratepayers has always been the Commission's authority to set retail rates. That authority is recognized by the new condition and is protected from many challenges that Progress would otherwise be able to assert." Id.

The Commission believes that the interpretation and application of Duke Power's Regulatory Condition No. 7(d)(iv) should be consistent with the comparable regulatory condition of Progress since the two are similarly worded and are intended to address the same issue. In order to accomplish this result, the Commission has revised the proposed Regulatory Condition No. 7(d)(iv) by changing "general statutory authority of" in the first sentence to "exercise of authority by" (which is the wording of the Progress condition) and by adding "based upon specific evidence of undue interference with interstate commerce" at the end of the second sentence (which is the interpretation of the Progress condition adopted by the Commission in the September 15, 2004 order in Docket No. E-2, Sub 844).

(b) Market-Based Tariffs. Market-based rates present additional issues that need to be addressed by the conditions in order to protect the Commission's jurisdiction. The FERC approved, by order dated November 22, 2005, the market-based tariffs filed August 19, 2005, by Cinergy Services, Inc., on behalf of CG&E, PSI, ULH&P, and Cinergy's marketing affiliates. These FERC-approved tariffs establish the rate that will apply to affiliate sales. Cinergy's filing explicitly states that the market-based rate tariffs proposed therein will be further amended prior to the Merger closing to include appropriate affiliate safeguards with respect to any relevant new Duke Energy affiliates. Regulatory Condition No. 4 is intended to protect the Commission's jurisdiction in this regard by prohibiting Duke Power from buying and selling electricity except as specifically provided in the condition. In addition, both Regulatory Condition No. 1 and Regulatory Condition No. 7 offer protection. Any proposed tariff revisions to include Duke Power will have to be pre-filed with the Commission pursuant to Regulatory Condition No. 1(c) 30 days in advance of their being filed with the FERC. The prohibitions against making various constitutional arguments in Regulatory Condition No. 7(d) are explicitly applicable to master and service agreements under Duke Power's market-based rate tariff.

The FERC's market-based tariff analysis also potentially raises preemption issues as to resource adequacy. Before allowing market-based pricing, the FERC has required a showing that there is direct head-to-head competition either in a formal solicitation or in an informal negotiation process that does not provide a preference to an affiliate.[1] The FERC has explicitly stated that this does not involve a determination that the buyer has evaluated all supply and demand-side options and prudently chosen from among them, noting that such a determination is primarily a state commission matter. However, an argument with respect to preemption could be made. While several of the conditions are relevant, Regulatory Condition No. 8 specifically prohibits Duke Power and its affiliates from asserting that approval by the FERC of market-based rates, transfers of generating facilities, or any matter that involves affiliates in any way preempts the Commission's authority to determine the reasonableness or prudence of Duke Power's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy.

(c) The Potential for a Holding Company System Integration Agreement. Because Cinergy currently is a registered holding company with multiple public utilities that formerly operated pursuant to a FERC-approved integration agreement,[2] the Public Staff notes in its brief that additional attention was paid to the potential risk of preemption in this regard. Due to the repeal of PUHCA 1935, Duke no longer intends to enter into a formal integration agreement as initially proposed in its FERC Merger Application. Even without this requirement, however, there is a risk that an inter-affiliate agreement could be interpreted as such an agreement.

There is little question that the FERC has exclusive jurisdiction to approve the wholesale rates paid and received by, and to approve the allocations of power among, public utility members of a holding company system. As a result, Regulatory Condition No. 9 specifically provides that Duke Power cannot enter into an agreement, and no filing with the FERC can be made by it or on its behalf, that (a) commits Duke Power to, or involves it in, joint planning, coordination, or operation of generation, transmission, or distribution facilities with one or more affiliates, or (b) otherwise alters Duke Power's obligations with respect to these Regulatory Conditions, absent explicit approval of the Commission.

In addition, Regulatory Condition Nos. 5 and 6 specifically impose a continuing obligation on Duke Power to pursue least cost integrated resource planning and remain responsible for its own resource adequacy subject to Commission oversight, and require that Duke Power's ratepayers receive priority with respect to the planning and dispatch of its system generation.

Regulatory Condition No. 10 provides added protection in this regard by requiring Duke Power and its affiliates to file notice with the Commission 30 days prior to filing with the FERC any agreement, tariff, or other document or any proposed amendments, modifications, or supplements to any such document having the potential to (a) affect Duke Power's cost of service for its pre-merger system power supply resources or transmission system; (b) be interpreted as involving Duke Power in joint planning, coordination, or operation of generation or transmission facilities with one or more affiliates; or (c) otherwise affect Duke Power's rates or service.

(d) Other Issues. Other potential preemption risks presented by the proposed Merger relate to (1) potential RTO membership, (2) Duke Power's Independent Entity (IE) Application at the FERC,

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[1] Boston Edison Co. Re: Edgar Electric Energy Co., 55 FERC ¶ 61,382 (1991).

[2] Until January 1, 2006, CG&E and PSI operated pursuant to the Joint Generation Dispatch Agreement approved by the FERC on March 18, 2002, Cinergy Services, Inc., 98 FERC ¶ 61,306 (2002), and revised on March 25, 2005, Cinergy Services, Inc., Letter Order, ER05-640-000 (dated March 25, 2005).

(3) Duke and Cinergy's FERC Merger Application, and (4) currently pending rulemaking proceedings and potential future revisions of PUHCA 2005 that could affect the proposed conditions.

With respect to RTO membership (and any proposed transfer of control, operational responsibility, or ownership), Regulatory Condition No. 3 requires a 30-day notice and specific protective language in any contract and in any filing with the FERC with respect to the transfer by Duke Power of the control of, operational responsibility for, or ownership of any generation, transmission, or distribution assets (in excess of $10 million gross book value) used to provide retail service to its North Carolina retail customers. In addition, Regulatory Condition No. 11 specifically requires any contract or filing regarding Duke Power's membership in or withdrawal from an RTO or comparable entity to be contingent upon state regulatory approval.

With respect to Duke Power's IE Application at the FERC, Regulatory Condition No. 12 provides that, if the FERC (1) does not approve the specified sections of the OATT Attachment K and Duke Power's IE Agreement dated July 22, 2005, both of which were filed with the FERC in Docket No. ER05-1236-000 on July 22, 2005, or (2) makes any change that would make the IE a FERC-jurisdictional entity or otherwise affect the Commission's jurisdiction over the transmission component of Duke Power's retail service or rates, then Duke shall withdraw the filing and exercise its right to terminate the IE Agreement, absent an order from the Commission explicitly relieving Duke Power of this obligation. Subsequent to the filing of the stipulated conditions, the FERC approved the IE Application without condition; however, this condition should be retained to protect against any subsequent orders that may be issued by the FERC.

With respect to potential preemption risks posed by Duke and Cinergy's FERC Merger Application, the Commission notes that the FERC has approved the Application without imposing any conditions of concern. However, at least one rehearing petition has been filed, and the FERC has not yet acted on that petition. Therefore, Regulatory Condition No. 16 explicitly provides that upon a decision by the FERC on the petition for rehearing, Duke Power shall meet promptly with the Public Staff and negotiate in good faith whether and how these Regulatory Conditions might be or have been affected by such order, and whether changes are necessary to maintain their intended protections. In the event the parties are unable to reach agreement within a reasonable time, the unresolved issues shall be submitted to the Commission for resolution. Such resolution would be subject to appeal.

Finally, Regulatory Condition No. 15 provides for subsequent determinations as to whether any condition would need to be revised based upon currently pending rulemaking proceedings that could affect the proposed conditions, and upon the repeal or revision of PUHCA 2005.

Additional conditions have been included to provide additional, more generic protections against the risk of preemption. Specifically, Regulatory Condition No. 13 prohibits Duke Power and its affiliates from asserting in any forum that the Commission is in any way preempted from exercising any authority it has under North Carolina law, and prohibits Duke and its affiliates from supporting such arguments if any other entity were to make them. Regulatory Condition No. 14[1] requires Duke Power and its affiliates to bear the full risk of any preemptive effects of federal law

[1] The Commission has revised proposed Regulatory Condition Nos. 14 and 29 to add "Affiliates" to the list of entities subject to the specific provisions set forth therein. This change would ensure that the language of these Regulatory Conditions is consistent with other Regulatory Conditions, such as Nos. 8, 10, 13, 14, 20, 22, 24, 27, etc. which apply to Duke Power, Duke Energy Corporation, Affiliates, and Nonpublic Utility Operations.

and to take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless.

(2) Inter-Affiliate Financings

With respect to issues presented by inter-affiliate financings, the Commission is familiar with these from issues raised in the Carolina Power & Light Company (CP&L) holding company proceeding (Docket No. E-2, Sub 753). In this regard, the Commission notes that § 204(a) of the FPA, 16 U.S.C. § 824c(a), provides the FERC with authority comparable to that granted to the Commission in G.S. 62-161. With respect to preemption, however, § 204(f) provides that the FERC's authority does not extend to a public utility organized and operating in a state in which its security issuances are regulated by a state commission. Thus, the FERC's financing authority does not encompass a public utility organized and operating in North Carolina.

While EPACT 2005 did not amend § 204, it did change the FERC's authority vis-à-vis the SEC. Section 318 of the FPA, 16 U.S.C. § 825q, provides that, with respect to the issuance, sale, or guaranty of a security or assumption of an obligation or liability in respect of a security, or the acquisition or disposition of any security, capital assets, facilities, or any other subject matter, if a person is subject to both PUHCA 1935 and the FPA, such person shall not be subject to the FPA with respect to the same subject matter. Section 1277(a) of EPACT 2005 repealed § 318. Thus, the FERC now has authority over the issuance of securities and the assumption of liabilities by public utilities that it previously could not have had. However, because § 204(f) has not been changed, the Commission concludes that this should have relatively little preemptive effect on the Commission's authority.

Although there appears to be relatively little risk of preemption with respect to the Commission's authority over financings, Regulatory Condition No. 2 provides that, with respect to any financing transaction involving Duke Power and its affiliates, any proposed contract must provide (1) that Duke Power may not enter into any such financing transaction except in accordance with North Carolina law and the Commission's rules, regulations, and orders and (2) that Duke Power may not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission. Regulatory Condition Nos. 13 and 14 again would serve as catch-all provisions in the unlikely event the other conditions did not control a particular risk of preemption.

(3) Mergers and Acquisitions under § 203 of the FPA, including Amendments to § 203 by EPACT 2005

The following issues are presented by § 203 of the FPA and the amendments in EPACT 2005 to the FERC's § 203 authority: (a) the expansion of the FERC's § 203 authority to include certain generating facilities and certain holding company transactions and (b) the requirement for findings about cross-subsidization and pledging and encumbrances of utility assets.

(a) Generating Facilities and Holding Company Transactions. Prior to the EPACT 2005 amendments, the FERC's authority under § 203 of the FPA, 16 U.S.C. § 824b, did not extend to transactions involving the acquisition of generating facilities or to certain acquisitions by holding companies. Section 1289 of EPACT 2005, in relevant part, amends § 203 of the FPA to include these types of transactions.

Amended § 203(a)(1)(D) states that no public utility shall, without first having secured an order of the FERC authorizing it to do so, purchase, lease, or otherwise acquire an existing generation facility (i) that has a value in excess of $10 million and (ii) that is used for interstate wholesale sales and over which the FERC has jurisdiction for ratemaking purposes. In its order implementing the amendments,[1] the FERC adopted a rebuttable presumption that amended § 203(a) as it applies to the transfer of any existing (i.e., operational) generation facility unless the utility can demonstrate with substantial evidence that the generating facility is used exclusively for retail sales.

The FERC's Section 203 Final Rule generally recognizes that Congress did not intend any infringement on state jurisdiction. In addition, as stated before, the FERC's jurisdiction under § 203 has always been viewed as concurrent with state jurisdiction. In any event, Regulatory Condition Nos. 1, 3, 8 and 10 all protect the Commission's jurisdiction in this regard. As discussed earlier, Regulatory Condition No. 8 specifically prohibits Duke Power and its affiliates from asserting that approval of a transfer of generating facilities by the FERC in any way preempts the Commission's authority to determine the reasonableness or prudence of Duke Power's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy. Regulatory Condition Nos. 13 and 14 again serve as catch-all provisions in the unlikely event the other conditions did not control a particular risk of preemption.

Section 203(a)(2) adds the entirely new requirement that no holding company in a holding company system that includes a transmitting utility or an electric utility shall (1) purchase, acquire, or take any security with a value in excess of $10 million or (2) by any means whatsoever, directly or indirectly, merge or consolidate with a transmitting utility, an electric utility company, or a holding company in a holding company system that includes a transmitting utility, or an electric utility company, with a value in excess of $10 million, without prior Commission authorization.[2]

The scope of amended § 203(a)(2) turns in large part upon the FERC's interpretation of the term "electric utility company," which, in turn, affects whether an entity is a holding company subject to § 203(a)(2). The FPA does not include a definition of "electric utility company," and the FERC concluded in its Section 203 Final Rule that the term, as used in amended § 203(a)(2), should have the same meaning as in PUHCA 2005, which is "any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale." EPACT of 2005 at § 1262(5).

Because of concerns expressed by parties to the rulemaking, the FERC included the following language in its Section 203 Final Rule:

> Our core jurisdiction under Part II of the FPA continues to be transmission and sales for resale of electric energy in interstate commerce and we believe that a major impetus behind § 203(a)(2) was to clarify the Commission's jurisdiction over mergers of holding companies that own public utilities as defined in the FPA. However, the fact is that the language in § 203(a)(2) does more than address this issue, and we must implement the provision in a way that

[1] Transactions Subject to FPA Section 203, Order No. 669, 113 FERC ¶ 61,315 (December 23, 2005) (Section 203 Final Rule).

[2] Section 203(a)(6), which is also new, provides that for purposes of this subsection, the terms "associate company," "holding company," and "holding company system" have the meaning given those terms in PUHCA 2005.

> recognizes the expansion of authority, yet retains our primary focus on interstate wholesale energy markets and does not interfere unduly with historical state jurisdiction.[1]

There appears to be relatively little risk of preemption as a result of this amendment to § 203. Nevertheless, to the extent there is any risk, Regulatory Condition Nos. 2, 13 and 14, as discussed above, apply.

(b) Cross-Subsidization. In its Section 203 Final Rule, the FERC required § 203 applicants to include an explanation of (1) how they are providing assurances that the proposed transaction will not result in cross-subsidization or improper pledges or encumbrances of utility assets or (2) if such results would occur, how those results are consistent with the public interest. With respect to the effect of this requirement on state jurisdiction, the FERC explicitly stated that any additional conditions imposed by it would complement, not nullify, those imposed by state commissions. The Commission therefore concludes that the conditions previously discussed in this section provide adequate protection from any risk of preemption.

(4) Inter-Affiliate Transactions Involving Non-Power Goods and Services under PUHCA 2005

The issues raised by PUHCA 2005 generally include the following: (a) federal access to books and records pursuant to § 1264; (b) the allocation of costs of non-power goods and services supplied to a public utility by an affiliated company, including the FERC's authority to review the recovery in jurisdictional rates, and whether cost allocation agreements have to be filed as agreements affecting jurisdictional rates; and (c) the potential for preemption pursuant to § 1275(b) at the request of a holding company system or a state commission.

Section 1261 et seq. of EPACT 2005, repeals PUHCA 1935 and enacts PUHCA 2005. As interpreted by the FERC in its implementing order,[2] PUHCA 2005 contains only two grants of new authority to the FERC: (1) the federal books and records access provision in § 1264 and (2) the non-power goods and services provision in § 1275(b), both of which supplement the FERC's existing authorities under the FPA (and the Natural Gas Act).

(a) Access to Books and Records. Sections 1264(a) and (b) of EPACT 2005 generally provide that each holding company and each associate company of a holding company, as well as each affiliate of a holding company or any subsidiary company of a holding company, shall maintain, and shall make available to the FERC, such books, accounts, memoranda, and other records (books and records) as the FERC determines are relevant to the costs incurred by a public utility and necessary or appropriate for the protection of public utility customers with respect to jurisdictional rates. With respect to preemptive concerns, the FERC confirmed that its own access under § 1264 does not preempt rights to access information by state commissions under § 1265.[3]

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[1] Section 203 Final Rule, ¶ 56.

[2] Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005, Order No. 667, FERC Stats. & Regs. ¶ 31,197 (December 8, 2005) (PUHCA 2005 Final Rule).

[3] Id., at ¶ 105.

(b) Section 1275: The Allocation of Costs of Non-Power Goods and Services. In its PUHCA 2005 Final Rule, the FERC stated that there are two circumstances in which the "at-cost" or "market" standard may arise in the context of its jurisdictional responsibilities under § 205 and § 206 of the FPA. First, the FERC has a responsibility to ensure that the costs of non-power goods and services provided by a traditional, centralized service company to public utilities within the holding company system are just, reasonable, and not unduly discriminatory or preferential for purposes of FERC-jurisdictional rates. The second context in which the "at-cost" or "market" standard is likely to arise is when a service company that is a special-purpose company within a holding company (e.g., a fuel supply company or construction company) provides non-power goods or services to one or more public utilities in the same holding company system.

The FERC concluded that traditional, centralized service companies currently using the SEC's "at-cost" standard would not be required to comply with the FERC's market standard for their sales of non-fuel, non-power goods and services to regulated affiliates. The FERC agreed with commenters that centralized provision of accounting, human resources, legal, tax, and other such services benefits ratepayers through increased efficiency and economies of scale. It, therefore, decided to apply a rebuttable presumption that costs incurred under "at cost" pricing of such services are reasonable, with the proviso that it would entertain complaints that "at cost" pricing for such services exceeds the market price.

With respect to non-power goods and services transactions between holding company affiliates other than traditional, centralized service companies (i.e., service companies that are non-regulated, special-purpose affiliates such as a fuel supply company or a construction company), the FERC concluded that it would continue its prior policy of requiring the service company to provide non-power goods and services at a price no higher than market. When a public utility is providing non-power goods and services, the price should be the higher of cost or market.

With respect to concerns that were expressed about the potential preemptive effect of FERC review of cost-allocation agreements, the FERC concluded that it would not mandate the blanket filing of cost-allocation agreements governing the costs of non-power goods and services purchased by jurisdictional public utilities from affiliated service companies under § 1275(b) of EPACT 2005.[1]

Based upon the foregoing, the Commission concludes that the provisions of PUHCA 2005 other than § 1275(b) do not present risks of preemption different from other aspects of the FERC's authority. As a result, the conditions previously discussed, particularly Regulatory Condition Nos. 1, 9, and 10, apply to protect the Commission's jurisdiction from preemption, with Regulatory Condition Nos. 13 and 14 again serving as catch-all provisions.

(c) The Potential for Preemption Pursuant to § 1275(b). With respect to the preemptive effect, if any, of a FERC-approved service company cost allocation, the FERC's PUHCA 2005 Final Rule does not clearly answer the question.

Section 1275(b) provides as follows:

> In the case of non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding

[1] Id., at ¶ 151.

> company system, at the election of the system or a State commission having jurisdiction over the public utility, the Commission [FERC], after the effective date of this subtitle, shall review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company.

In its comments in response to the FERC's Notice of Proposed Rulemaking, the Missouri Public Service Commission argued that an interpretation of § 1275(b) giving FERC-approved cost allocations preemptive effect would be contrary to the clear language contained within § 1275(c), which provides that "[n]othing in this section shall affect the authority of the Commission or a state commission under other applicable law." The Missouri Commission further argued that, since state commissions have state law authority to set retail rates, including authority to disallow purchase costs or sales prices deemed unreasonable or imprudent, § 1275(c) on its face protects the state commissions from any asserted preemptive effect of a FERC allocation under § 1275(b). A number of utilities argued (1) that the FERC would need to impose a specific methodology in a situation in which a multi-state holding company system finds that all state commissions do not approve a single allocation agreement and (2) that any FERC-approved cost allocations under § 1275 would necessarily preempt state determinations.

The FERC concluded as follows:

> In response to the requests for clarification of the preemptive effects of section 1264 and the Commission's regulations thereunder, we believe that issues related to preemption are more appropriately addressed on a case-by-case basis to give the Commission the opportunity to consider the potential preemptive effect of section 1264 in specific circumstances. However, we anticipate that such issues would arise only in unusual circumstances.[1]

Given the reference to § 1264, rather than § 1275(b), which was the section under discussion in the preceding paragraphs of the FERC order, the FERC's position with respect to the preemptive effect of § 1275(b) cannot be conclusively determined.

The Regulatory Conditions and Code of Conduct adopted herein impose fairly strict rules with respect to affiliate transactions, particularly with respect to those involving a service company, and the Commission maintains comprehensive oversight of Duke Power's affiliated transactions and cost allocations. For example, under Regulatory Condition No. 18, Duke Power cannot seek to recover from its retail customers any costs that exceed fair market value (as defined in the conditions) for any service provided to Duke Power by an affiliate, and Duke Power is required to seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services. Duke Power has the burden of proving that all goods and services procured from its affiliates have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which must include a showing that comparable goods or services could not have been procured at a lower price from qualified non-affiliate sources or that Duke Power could not have provided the services or goods itself on the same basis at a lower cost.

Under Regulatory Condition No. 20, Duke Power is required to re-file its proposed final forms of service agreements that authorize the provision and receipt of non-power goods or services

[1] Id., at ¶ 180 (emphasis added).

between and among Duke Power and its affiliates, the lists of goods and services it intends to take from the proposed service company and other affiliates, the basis for the determination of such lists and election of such services, and appropriate cost allocation manuals (CAMs). The required CAMs must be updated annually, and neither the lists of goods and services nor the CAMs can be changed except upon the filing of a 15-day notice with the Commission.

Except to the limited extent to which Regulatory Condition No. 21 provides otherwise, no claims of preemption can be made with respect to the allocation of costs. In addition, Regulatory Condition No. 21 does not apply to the list of services a utility chooses to take from a service company, and, therefore, neither Duke Power nor Duke Energy can make any claims of preemption with respect to the services the Commission allows Duke Power to take. For example, under Regulatory Condition No. 18, Duke Power cannot take a service from a service company unless it has carried its burden of proving that it could not have procured the service at a lower price from qualified non-affiliate sources, that it could not have provided the service itself on the same basis at a lower cost, or that no comparable service is available. Requiring Duke Power to provide the service for itself or to take it from a non-affiliate is not subject to any preemptive effect that § 1275(b) may ultimately be determined to have.

In addition, the exception provided in Regulatory Condition No. 21 with respect to the other anti-preemption conditions is more limited than the provisions of §1275(b). This section allows the holding company system to request review by the FERC. Regulatory Condition No. 21 only allows Duke Power to make such a request. In addition, any such request is limited to "the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of Duke Power result in significant trapped costs," which is considerably narrower than the language used in § 1275(b).

In conclusion, it is not clear that § 1275(b) will have any preemptive effect given the savings clauses in PUHCA 2005 and the FERC's interpretation in its PUHCA 2005 Final Rule (particularly if one assumes that the reference to § 1264 was inadvertent). If it does, it is further limited as described above. The Public Staff stated in its brief that it believes that allowing this potential narrow preemption risk was an appropriate trade off given the waiver of all the federal rights by Duke Power, Duke Energy, and other affiliates in the other conditions, and the Commission agrees.

In addition to the above discussion of the anti-preemption Regulatory Condition Nos. 1 through 17, the Commission must also address in more detail several specific arguments and proposed revisions made by CUCA.

CUCA's primary substantive attack on the effectiveness of the anti-preemption conditions is the argument that the conditions do not protect Duke Power's ratepayers from an assertion of preemption by third parties. The Commission concludes that many of the conditions do provide such protection. An excellent example is Regulatory Condition No. 1, which makes an affiliate contract unenforceable against Duke except to the extent the Commission approves the costs. Regulatory Condition No. 1 limits the utility's obligation to pay charges under the contract to those charges determined by the Commission to be consistent with the utility's obligation under state law to charge just and reasonable rates. As previously discussed, this approach responds directly to the "trapped cost" reasoning of the Supreme Court. If a FERC-jurisdictional contract itself provides that the utility's participation is voluntary and limits the utility's obligation to one that is consistent with state law, there would be no "trapped costs" and, therefore, no preemption. Regulatory Condition Nos. 2

and 3, which apply to financings and asset transfers, respectively, are very similar to Regulatory Condition No. 1. They also provide protection against challenges by third parties.

It is difficult to perceive how a third party would have standing to challenge Regulatory Condition Nos. 5 though 7 on preemption grounds. If a third party were found to have standing, it is difficult to perceive how it could successfully argue that the Commission's authority to require least cost planning, the dedication of Duke Power's generating facilities to retail native load customers (as defined in the conditions), and the Commission's ratemaking and other types of authority with respect to Duke Power's wholesale contracts as seller was preempted. The retail loads of the historically served wholesale customers are the only third parties that have any sort of claim on Duke Power's generating facilities, and they have been included in the protections provided by Regulatory Condition Nos. 5 though 7.

Regulatory Condition No. 10 requires the pre-filing of certain contracts that are required or intended to be filed at the FERC. Given the North Carolina appellate courts' recent affirmations of the Commission's authority relating to the 20-day notice required by the Commission in Docket No. E-2, Sub 760 (appealed in Docket No. E-100, Sub 85A), a successful third-party challenge to this condition appears to be unlikely.

The provisions of Duke's OATT and IE Agreement referenced in and protected by Regulatory Condition No. 12 have already withstood numerous arguments before the FERC that they should be rejected. The FERC approved the OATT without change to the provisions protecting the ability of Duke to withdraw the OATT and terminate the IE Agreement if a negative effect on the Commission's jurisdiction were to occur.

Regulatory Condition No. 13 recognizes that another entity could make preemption arguments and prohibits Duke Power and its affiliates from supporting any such arguments. This condition is similar to several conditions imposed, without objection by CUCA, in various merger proceedings. See Docket Nos. E-2, Sub 753 (Condition Nos. 2, 7, and 12); E-2, Sub 760 (Condition No. 15); E-22, Sub 380 (Condition Nos. 31, 38, and 41); G-5, Sub 400 (Condition Nos. 2, 9, and 12); and E-2, Sub 844 (Condition Nos. 6, 9, and 11).

Finally, Regulatory Condition No. 14 provides the ultimate protection. It requires Duke Power and its affiliates to (1) bear the full risk of any preemptive effects of federal law with respect to any contract, transaction, or commitment entered into or made by Duke Power or which may otherwise affect Duke Power's operations, service, or rates and (2) take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless.

In conclusion, as demonstrated above, the anti-preemption conditions are not particularly susceptible to third-party challenges. In any event, they require Duke Power and its affiliates to bear any effects and hold Duke Power's ratepayers harmless from any preemption.

CUCA's other objections do not go to the effectiveness of the conditions as protection against preemption, but rather are specific proposals that object to the wording of the conditions.

During the hearing, counsel for CUCA cross-examined the Public Staff with respect to the meaning of "affect Duke Power's rates or service" and "have an effect on Duke Power's rates or service" in a number of conditions. In response, Duke and the Public Staff proposed to create a definition of "Effect on Duke Power's Rates or Service" and replace "affect Duke Power's rates or service" and "have an effect on Duke Power's rates or service" in the definition of "Affiliate Contract," and in Regulatory Condition Nos. 2(b), 10, 13, and 22. That definition is as follows:

> **Effect on Duke Power's Rates or Service:** When used with reference to the consequences to Duke Power of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

The Public Staff explained at the oral argument that the purpose of this definition and its use in the specified conditions was to incorporate into the Regulatory Conditions the concept in G.S. 62-3(23)(c) with respect to the extent to which affiliation can cause an affiliate to be found to be a public utility.

In the revised conditions it filed on January 17, 2006, CUCA proposed to replace "affect Duke Power's rates or service" and "effect on Duke Power's rates or service" with a different defined term, "Effect." This defined term would be included in the definition of "Affiliate Contract," Regulatory Condition Nos. 2(a), 10, 13, 14, and 17, as well as in Regulatory Condition Nos. 20(d), 22, 23, 26,27, 28, 29, 32, 38, 55, and 57. CUCA would define the term "Effect" as follows:

> **Effect:** Any effect on Duke Power's rates and/or services to its North Carolina retail customers, including but not limited to an increase in fuel costs or fuel-related costs for which Duke Power seeks recovery pursuant to G.S. 62-133.2, a change of one (1) basis point (one-tenth of one percent) or more in Duke Power's quarterly or annual earnings in the ES-1 report, a ratings downgrade, a change of $100,000 or more in the net bulk power revenues ordered to be shared by the Commission in Docket No. E-7, Sub 751, an appreciable change in service quality perceptible by a reasonable person, asset transfers and sales, and change(s) in operation, efficiency, interchange, pooling, wholesale power sales agreements, and financing.

CUCA stated at the oral argument that more specificity was needed in the conditions, particularly with respect to establishing a floor to ensure that it was clear that a particular contract or action fell within a condition. Duke Energy and the Public Staff took the position that specifically defining a term can lead to unintended consequences over time and limit the Commission's ability to make appropriate case-by-case determinations based upon the facts at the time the determination is made. They also argued that attempting a specific definition could create confusion as to the meaning of the term in its broader application in Chapter 62. The Commission concludes that CUCA's proposed definition should be rejected. The terms "effect" and "affect" are used in Chapter 62 without definition, so the Commission has the ability to determine their meanings based upon the facts and circumstances of each case at the time the interpretation is made. It is the Commission's responsibility to decide in a particular case whether a transaction or action has the necessary effect. CUCA's proposed definition could be both too limiting and not limiting enough, depending upon the particular circumstances to which it is being applied.

In addition, CUCA proposed to insert "any adverse Effect to Duke Power's North Carolina retail ratepayers" into Regulatory Condition No. 2(b) and "Effect that is adverse to the ratepayers' interest associated with or related to [such preemption]" into Regulatory Condition No. 14. The term "Effect," as defined by CUCA, already includes a substantial list of adverse effects. While CUCA explained this additional language at the oral argument as reflecting a desire to capture any positive effects, the Commission finds it to be an added complication that is unnecessary.

CUCA also proposed to revise Regulatory Condition No. 2(a) to deem new Duke Energy to be a public utility for purposes of the Commission's securities authority and G.S. 62-111 and to have waived all of its federal and constitutional challenges with respect to such authority. This is an expansion of the Commission's authority, rather than a protection of the Commission's authority from preemption. This would be more appropriately accomplished, if at all, with a revision to Regulatory Condition No. 41, and it is discussed in that section of this order.

CUCA further proposed to revise Regulatory Condition No. 3 to state that it applies to transfers that, either alone or collectively, have a gross book value in excess of $10,000,000 in any calendar year. Duke Energy and the Public Staff argued that the condition as written provides sufficient protection. The book value of $10,000,000 proposed in Duke Energy and the Public Staff's stipulated conditions would be a very small fraction of Duke Power's gross book value. Additionally, subjecting such a small amount to the condition would be an inefficient use of resources. Furthermore, it is illogical to approve a condition that could require Duke Power to provide notice, after having made transfers totaling $9,900,000, for a transfer of $101,000. The Commission concludes that CUCA's proposed revision should be rejected.

In addition, CUCA proposed to revise Regulatory Condition No. 4 to clarify its relationship to various sections of the Code of Conduct, to specify that the costs incurred are "total all-in" costs, and to delete the exception for emergency transactions. The Commission concludes that this condition should be revised to specify that the costs incurred are "total all-in costs, including, but not limited to, generation, transmission, ancillary costs, distribution, and delivery points costs," but that the exception for emergency transactions should be retained. This exception has been approved in other proceedings without objection or need for revision. See Docket No. E-2, Sub 760 (Condition No. 18) and Docket No. E-2, Sub 844 (Condition No. 54). As noted by the Commission during the oral argument, any such emergency transactions would be tracked, accounted for, and subject to review in both the required affiliate transaction report and in fuel clause proceedings. By their very nature, emergency transactions cannot be planned or subjected to rigid before-the-fact limitations. A utility must have some flexibility in the relatively few instances when the integrity of its transmission system, for example, requires unusual actions and transactions.

CUCA further proposed to revise Regulatory Condition No. 6 to delete "off-system" and to substitute "outside of its North Carolina and South Carolina retail franchised service territory or to any wholesale customer." This language would treat historically served wholesale customers as off-system sales, which is inconsistent with the protections intended by the condition. Duke Energy and the Public Staff took the position that "off-system sales" should be deleted, but that it should be replaced with "sales to customers that are not Retail Native Load Customers." The Commission concludes that "off-system sales" should be replaced as proposed by Duke Energy and the Public Staff. CUCA's replacement language would exclude the historically served wholesale customers from protections intended to be granted to them in Regulatory Condition No. 7.

With respect to Regulatory Condition No. 7, CUCA proposed to delete subsection (a) in its entirety. This provision would allow Duke Power to grant its historically served wholesale customers native load priority, which would cause the retail native loads of those wholesale customers to be considered Retail Native Load Customers, as defined in the conditions, for purposes of Regulatory Condition Nos. 5 and 6. The Commission rejects CUCA's proposal to delete this provision for much the same reasons it found unpersuasive CUCA's opposition to including CP&L's historically served wholesale customers in a virtually identical condition approved by the Commission in Docket No. E-2, Sub 844. The Commission concludes that, given the interpretation of the condition as provided for in the Sub 844 proceeding and the benefits to all customer classes from such a condition, subsection (a) of Regulatory Condition No. 7 should not be deleted. CUCA's two additional proposed changes, to increase the notice period in Regulatory Condition No. 7(b) from 30 to 45 days and to delete the provision that exempts wholesale sales at less than native load priority from the notice provision, are also rejected.

CUCA also proposed to revise Regulatory Condition No. 17 to require Duke Power to provide the required lists and summaries to "the Public Staff and each Requesting Intervenor" and to provide, in addition to the lists and summaries already included in the condition, a list of each affiliate that has made one or more filings with the FERC and a summary of the content of each filing if the filing is made under seal. Duke Power and the Public Staff subsequently proposed revisions to Regulatory Condition No. 17 to require Duke Power to file with the Commission, but not serve, the required lists and summaries. The Commission concludes that Regulatory Condition No. 17 already requires Duke Power to compile and file with the Commission a substantial amount of information on a quarterly basis and that Duke Power should not be required to file the additional lists and summaries sought by CUCA. However, the Commission agrees with CUCA that all parties should receive copies of any information actually filed by Duke Power pursuant to Regulatory Condition No. 17, and the Commission will not include the phrase "but need not serve" in the condition. Duke Power, therefore, shall serve any information filed with the Commission pursuant to Regulatory Condition No. 17 on all parties, if any, to the applicable docket.

Finally, CUCA's proposal to define "Requesting Intervenor" and insert it into various conditions, including Regulatory Condition Nos. 1(a) and (c), 13, 15 and 17, is discussed and rejected later in this order.

In summary, based upon all of the foregoing, the Commission concludes that the Regulatory Conditions approved herein are comprehensive and do everything reasonably possible to preserve the Commission's regulatory authority from the probability and risk of federal preemption. The mere risk of federal preemption as an abstract theory does not justify rejection of the proposed transaction. The slight risk that might remain, therefore, is entitled to very little weight in the balancing of the potential benefits and harms of the Merger identified in the record in this proceeding. Accordingly, based upon the conclusions of law discussed above with respect to the effectiveness and comprehensiveness of Regulatory Condition Nos. 1 through 17 approved herein, the Commission finds and concludes that Regulatory Condition Nos. 1 through 17 ensure that the Commission's jurisdiction is protected as much as possible from the probability of federal preemption and that Duke Power's ratepayers are insulated as much as reasonably possible from the probability of any preemptive consequences potentially resulting from the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witnesses Hager and Shrum and Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff testified that Regulatory Condition No. 18 provides that Duke Power will not seek to recover more than fair market value for the services and costs provided by affiliates and establishes principles that will govern the prices at which goods and services are exchanged between and among Duke Power and its affiliates. Regulatory Condition No. 19 requires that the accounting for the provision of good and services among Duke Power and its affiliates be consistent with the conditions and Code of Conduct.

Regulatory Condition No. 20 deals with service agreements, the filing of cost allocation manuals and the lists of services Duke Power intends to offer to and take from affiliates. While the Public Staff believes efficiencies and cost savings can be achieved by the combination of a number of corporate and utility support functions, the service agreements as filed raise a number of concerns. Therefore, Regulatory Condition No. 20 sets forth procedures for the re-filing of the service agreements and recommendations from the intervening parties. In this regard, the Public Staff noted that Regulatory Condition No. 20 requires Duke to re-file final forms of service agreements and the lists of goods and services it intends to take from and provide to its affiliates no later than 60 days prior to the expected close of the Merger. Within 30 days after such filing, the Public Staff is required to file its comments and recommendations concerning these agreements with the Commission. Therefore, the Public Staff recommended that the Commission address these agreements after Duke Power has made its filing pursuant to Regulatory Condition No. 20 and the Public Staff and other parties have filed their recommendations with the Commission.

Regulatory Condition No. 21 provides that, notwithstanding any of the provisions contained in the conditions, if allocations adopted by the Commission result in significant trapped costs related to non-power goods or administrative or management services, Duke Power may request, pursuant to EPACT 2005, that the FERC review the allocation of costs for such goods and services.

On cross-examination, the Public Staff testified that the purpose of the periodic market studies in Regulatory Condition No. 18 was to establish the reasonableness of the prices paid and the prudence of choosing to purchase from and sell to affiliates. When questioned about the frequency of the market studies and the reliance on Duke to perform the market studies, the Public Staff testified that how often market studies should be performed depends on the type of goods and services procured or provided and that Duke should be required to conduct the studies, rather than another entity, because it is in the market of purchasing goods and services. The Public Staff further stated that it would review the market studies and, because other utilities are subject to the same requirement, it can compare Duke's studies with other studies to determine their reasonableness.

Another issue raised on cross-examination of the Public Staff panel regarding Regulatory Condition No. 18(d) was the definition of, and exception for, items that are not commercially available. The Public Staff defined "not commercially available" as there being no equivalent service available in the market place, with the example of executive management as something specific or unique to Duke. When questioned by the Commission about the exception to transfer pricing for providing services from the service company to affiliates at fully distributed cost, Duke Energy witness Shrum stated that the conditions require that Duke be able to demonstrate on a periodic basis that costs coming from the shared services organization are comparable or better than market to show that Duke is not being charged more than it could secure those services elsewhere. She testified that, in Duke's current ongoing operations, it does comparisons to market on an annual basis for certain types of costs.

CUCA proposed that the market studies required by Regulatory Condition No. 18 be conducted by an independent auditor and that market studies be required every two years. Additionally, CUCA proposed to eliminate the "not commercially available" exception to the market study requirement.

After careful consideration, the Commission concludes that Duke Power should be responsible for conducting market price studies and that the frequency with which market price studies should be performed should not be set at two years, but rather the frequency should be determined based upon the nature of the goods and services being procured. Similar conditions have been approved without objection in other proceedings. (See Docket Nos. E-2, Sub 753 (Condition 21), E-2, Sub 380 (Condition 19) and E-2, Sub 844 (Condition 17).) In addition, the Commission concludes that it is appropriate to make an exception to Regulatory Condition No. 18 for goods or services that are not commercially available. The exception was included to recognize that market studies are unnecessary for goods or services that are not commercially available. This language is consistent with Duke's current Code of Conduct and with other Codes of Conduct approved by the Commission.

With respect to CUCA's concern about Regulatory Condition No. 20, on cross-examination, Duke witness Shrum was asked why Duke could not file the cost allocation manual prior to filing the service agreements and prior to asking for approval. She testified that the services agreements would tell the Commission how Duke plans to allocate the service company costs and that more time was needed to comply with the requirement.

The Public Staff panel testified that Duke Power is required to file the list of services that it intends to take from the service company and provide the basis for the election of services to be taken. Additionally, Regulatory Condition No. 20 requires Duke to file a revised CAM a month after the Merger closes, an annual update of the CAM, and a review of the allocation factors every two years.

CUCA proposed that CAM revisions should be filed prior to Duke Power undertaking the affiliate transactions and that the allocation factors in the CAM should be approved by the Commission and audited by a third-party independent auditor to ensure appropriate allocations.

After careful consideration, the Commission concludes that Regulatory Condition No. 20, as approved herein, is appropriate. Moreover, as discussed below, these conditions are intended to establish much broader and more detailed requirements related to pricing between and among affiliates and Duke Power's nonpublic utility operations than currently are in effect for Duke pursuant to orders in Docket No. E-7, Subs 694 and 596.

CUCA also proposed revising Regulatory Condition No. 21 to more specifically define "trapped cost" for purposes of Duke Power's ability to avail itself of the provisions of § 1275(b) of PUHCA 2005. As discussed earlier, Regulatory Condition No. 21 represents an appropriate balancing of interests and would not be improved by the revisions proposed by CUCA. Accordingly, its proposed revisions are rejected.

Based upon all of the foregoing, the Commission finds and concludes that Commission-approved Regulatory Condition Nos. 18 through 21 will effectively address known and potential risks and concerns related to cost allocation and ratemaking issues arising from the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn, CUCA witness O'Donnell, and Duke Energy witness Shrum.

The Public Staff witnesses testified that proposed Regulatory Condition No. 22 provides that affiliated transactions that are likely to have a significant effect on Duke Power's rates or service shall be reviewed annually by Duke Energy's internal auditors. The witnesses further testified that proposed Regulatory Condition No. 31 continues the current requirement that Duke Power file an annual report of affiliated transactions, and proposed Regulatory Condition No. 32 provides for the filing of third-party independent audit reports. With respect to cost of service, Further Revised Regulatory Condition No. 33 requires the filing of revisions to Duke Power's electric cost of service manual to reflect any changes to the cost of service resulting from the Merger.

Commission-approved Regulatory Condition No. 22 provides that transactions between Duke Power and other members of the Duke Energy holding company family that are reasonably likely to have a significant Effect on Duke Power's Rates or Service must be reviewed at least annually by Duke Energy's internal auditors. Moreover, the audits and all workpapers related to internal audits and all other internal audit workpapers related to affiliate transactions must be made available to and for review by the Public Staff and the Commission. Finally, Duke Energy will not oppose requests by the Public Staff or the Commission to review external audit workpapers.

CUCA's proposed Regulatory Condition No. 22 would apply to transactions that "either alone or collectively, will have or are reasonably likely to have an Effect [a defined term discussed elsewhere in this order]" and would place each Requesting Intervenor [another proposed defined term discussed elsewhere] along side the Public Staff.

With respect to applicability of this condition, the Commission believes CUCA's proposed change is unnecessary, as the consideration of whether affiliate transactions have a significant effect can take into account the interdependencies of affiliate transactions. The Commission also rejects CUCA's proposal that "each Requesting Intervenor" have the same right of access to audit reports and workpapers as the Commission and the Public Staff for the reasons given elsewhere in this order.

Regulatory Condition No. 31 provides that Duke Power shall file an annual report of affiliate transactions in the format prescribed by the Commission in Docket No. E-7, Sub 694. Changes may be made as necessary to the reporting requirements and submitted to the Commission for approval. None of the parties took issue with Regulatory Condition No. 31.

There was extensive testimony concerning third-party independent audits of affiliate transactions. Regulatory Condition No. 32, as originally proposed, required Duke Power to provide to the Public Staff and the Commission the third-party independent audit reports that were agreed to be submitted to the Kentucky Commission and the Attorney General in the stipulation in Case Number 2005-00228. Public Staff witness Cox testified that an independent audit would be conducted of affiliate transactions and that, to the extent that Duke Power participated in affiliate transactions related to the Service Agreements, such audit would cover those affiliate transactions. Witness Cox explained that it would be beneficial for there to be coordination between the states concerning the audit process. CUCA witness O'Donnell testified that he would be more satisfied if this Commission required an independent audit specific to North Carolina as opposed to the Kentucky audit.

Proposed Regulatory Condition No. 32, as further revised by Duke Power and the Public Staff in their filing of January 27, 2006, provides that comprehensive third-party independent audits of affiliate transactions undertaken pursuant to the affiliate agreements filed in this docket will be conducted no less often than every two years and that the independent auditor will have sufficient access to the books and records of Duke Energy to perform the audits. Duke Power is required to identify one or more proposed independent auditors with the selection subject to Commission approval. Other parties may comment and propose additional auditors. Duke Power will provide the funds for the audit and will record the appropriate allocation of the cost of the audit in utility accounts, subject to review in a subsequent ratemaking proceeding. The auditor's reports will be filed with the Commission. Duke Power may request a change to the frequency of the audits in future years, subject to Commission approval. Duke Energy will endeavor to coordinate the affiliate transaction audits in the various states. To the extent separate independent audits continue to be performed in any of the states, Duke Power will provide the audit reports to the Public Staff and the Commission.

CUCA's proposed Regulatory Condition No. 32 would require comprehensive third-party independent audits of all affiliate transactions to which Duke Power is a party and all affiliate transactions that "have an Effect or are reasonably likely to have an Effect." The auditor would have sufficient access to the books and records to perform the audits. The audit reports would be provided to the Public Staff and each Requesting Intervenor. The independent auditor would be selected by the Commission, in cooperation with regulatory agencies in other states, from a list nominated by the Requesting Intervenors. The independent auditor would not be a governmental agency or a division of such an agency. The auditor's fees would be paid by Duke Energy to the Commission, which would be responsible for retaining the auditor and remitting the payments to the auditor.

After careful consideration, the Commission concludes that Regulatory Condition No. 32 should be modified to read as follows:

> Periodic comprehensive third-party independent audits of the affiliate transactions undertaken pursuant to the affiliate agreements filed in this docket (as subsequently re-filed in accordance with Regulatory Condition No. 20 and allowed to go into effect by the Commission) shall be conducted no less often than every two years. The independent auditor shall have sufficient access to the books and records of Duke Power, Duke Energy Corporation, other Affiliates, and all of the Nonpublic Utility Operations to perform the audits. The scope of the audits shall include Duke Energy Corporation's and Duke Power's compliance with all conditions ordered herein concerning affiliate company transactions, including the propriety of the transfer pricing of goods and services between and/or among Duke Power and its affiliates, that is, Duke Energy Corporation, other Affiliates, and all of the Nonpublic Utility Operations. Duke Power and the Public Staff shall confer and jointly identify one or more proposed independent auditors. Other parties shall have an opportunity to comment and propose additional auditors. Selection of the independent auditor shall be made by the Commission. The independent auditor shall be supervised in its duties by the Public Staff. Not later than 60 days after consummation of the Merger, the Public Staff shall file a recommendation with the Commission as to how and when the

first independent audit should be commenced. Duke Energy Corporation shall bear the cost of the audits, and all such costs shall be excluded from Duke Power's utility accounts, except to the extent that reasonable assignments or allocations of such audit costs may be included in the transfer prices charged to Duke Power for goods and services provided to it by Duke Energy Corporation, other Affiliates, and all of the Nonpublic Utility Operations; provided however, that such transfer prices, individually, shall not exceed prices determined in strict compliance with all other Regulatory Conditions and the Code of Conduct as prescribed herein. The appropriateness of the assignment or allocation of the cost of the audits to utility accounts in the manner described above, if any, shall be subject to review in subsequent ratemaking proceedings. The auditor's reports shall be filed with the Commission. Duke Power may request a change in the frequency of the audit reports in future years, subject to approval by the Commission. Duke Energy Corporation shall endeavor to coordinate the various state affiliate transaction audits. To the extent separate third-party independent audits continue to be performed in the other states, Duke Power shall provide the reports of those audits to the Public Staff and the Commission.

The additional changes and modifications adopted and required by the Commission with respect to Regulatory Condition No. 32 significantly strengthen the consumer protections afforded to North Carolina retail ratepayers which such Condition is designed to provide. These changes guarantee that the independent auditor will have access to all records necessary to ensure the integrity, completeness, and scope of the audit process. In addition, the Public Staff, fulfilling its statutory duty to represent the interests of North Carolina retail consumers, has been designated by the Commission to play a crucial and integral role in the audit process as supervisor of the independent auditor.

Appropriate provisions for the assignment and allocation of audit costs have also been adopted to ensure that North Carolina retail ratepayers of Duke Power are not improperly, unduly, and/or unfairly burdened by such costs. In particular, the Commission has done so as it is of the opinion that it would be unfair and unreasonable to indiscriminately saddle ratepayers with costs incurred to protect them from the potential abuse that arises from the creation of a holding company arrangement, particularly in consideration of the fact that such an arrangement was requested by Duke Energy. Strict and extensive affiliate transfer pricing rules and other conditions have been adopted herein to protect ratepayers against that potential holding company abuse. The independent audit is crucial to determining whether those rules have been appropriately implemented and whether they are being exactingly followed. Therefore, inasmuch as the audit, including its attendant cost, is made necessary by virtue of creation of the holding company arrangement, as requested by Duke Energy, the Commission is of the view that such cost should not be borne by the North Carolina retail ratepayers of Duke Power, except to the extent, if any, as discussed below.

In reaching this decision regarding the cost of the audit, the Commission has been mindful of the fact that efficiencies and cost savings may be realized by Duke Power and its ratepayers as a result of the holding company arrangement. Therefore, the Commission has included provisions in this regard that would allow audit cost to be passed through to ratepayers as a component of the transfer prices charged for goods and services provided by Duke Energy Corporation, other affiliates, and Nonpublic Utility Operations to Duke Power, provided however, that such transfer prices are determined in strict compliance with other Regulatory Conditions and the Code of Conduct as prescribed herein.[1]

The provisions of Regulatory Condition No. 32 have been reinforced by the Commission to ensure, to the maximum extent possible, that the Merger will have no adverse impact on the rates charged and the services provided to Duke Power's North Carolina retail ratepayers and that ratepayers are sufficiently protected and insulated from potential costs and risks resulting from the Merger.

Furthermore, in so ruling, the Commission has declined to adopt CUCA's proposal to require an independent audit of all affiliate transactions to which Duke Power is a party and other affiliate transactions that have an effect on Duke Power's rates or service, as defined by CUCA. The Commission believes it is sufficient for purposes of this proceeding to require an independent audit only of transactions pursuant to the affiliate agreements filed in connection with the proposed Merger. The Commission has ample authority to require an audit by the Public Staff or an independent third party of other affiliate transactions should such an audit appear warranted in the future.

The Commission, therefore, finds and concludes that the Commission-approved Regulatory Conditions as discussed hereinabove will impose appropriate and effective auditing and reporting requirements with respect to affiliate transactions and cost of service.

Additionally, as an added measure to further protect North Carolina retail ratepayers from future potential negative consequences that may arise from the Merger, if any, the Commission is of

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[1] For example, with regard to transfer pricing, the Code of Conduct required by the Commission-approved Regulatory Conditions as adopted herein, among other things, in pertinent part, provides as follows:

> Part III, Section D(3)(b): Except as otherwise provided for in this Section D, for goods and services, provided, directly or indirectly, by Duke Energy Corporation, an Affiliate, or a Nonpublic Utility Operation to Duke Power, the transfer price(s) charged by Duke Energy Corporation, the Affiliate, and the Nonpublic Utility Operation to Duke Power shall be set at the lower of Market Value or Duke Energy Corporation's, the Affiliate's or the Nonpublic Utility Operation's Fully Distributed Cost(s) . . .

Therefore, with certain noted exceptions, the present provision effectively places a ceiling on the transfer prices that may be charged to Duke Power by an affiliate for goods and services provided by the affiliate to Duke Power. The ceiling price is the lower of "market value" or the affiliate's "fully distributed cost." Thus, in determining the transfer price(s) to be charged for goods and services subject to this pricing provision of the Code of Conduct, the "market values" and "fully distributed costs" of such goods and services must be determined. In determining "fully distributed cost," under the Commission's instant ruling, it would be entirely proper to include an appropriate proportional share of the audit cost in the "fully distributed cost" of each good or service. If "fully distributed cost," including an appropriate share of audit cost, was the same as or less than "market value," then and in that event such audit cost would be properly chargeable to Duke Power's regulated electric utility operations. However, if "fully distributed cost" exceeded "market value," the transfer price would be limited to "market value" and the audit cost, either in whole or in part, would not be chargeable to or recoverable from Duke Power's North Carolina retail ratepayers.

To the extent audit cost is included in determining the appropriateness of transfer prices and/or is otherwise included in assessments of the net benefit(s) of the instant affiliate relationships, the Commission is of the opinion, and so concludes, that the audit cost should be appropriately assigned or allocated, at a minimum, to all goods and services of all affiliates engaged both directly and indirectly in providing goods and services to Duke Power. Further, to the extent the cost of an audit is deferred for potential recovery from Duke Power's North Carolina retail ratepayers, such cost shall not be eligible for recovery for a period any longer than 24 months from the date the audit report is filed with the Commission.

the opinion that the following Regulatory Condition requiring Duke Power to track its actual net merger savings should be added to those proposed by Duke Energy and the Public Staff:

> 32a. Duke Power shall track its actual net merger savings for the five-year period beginning immediately subsequent to consummation of the Merger and submit quarterly reports delineating the actual net benefits derived therefrom with respect to its North Carolina retail operations. Said reports shall include explanations of the methodologies, assumptions, judgments, and estimates, if any, on which the reports are based. Copies of the workpapers setting forth the calculations of the net merger savings shall also be provided. These reports shall be verified by either the Chief Executive Officer, a senior-level financial officer, or the responsible accounting officer of Duke Power and shall be provided in conjunction with Duke Power's quarterly NCUC ES-1 Reports. The Public Staff is hereby requested to investigate, verify, and assess the reports required in this regard and submit an annual report to the Commission setting forth its findings and recommendations. It is further requested that the Public Staff's annual report be submitted on or before June 1st with respect to Duke Power's quarterly reports for the preceding calendar year.

This Regulatory Condition, which requires Duke Power to track the actual benefits and costs of the Merger, should provide the Commission with additional meaningful information that will allow it to monitor the actual effect that the Merger is having on North Carolina retail ratepayers, thereby helping to ensure that such ratepayers are, in fact, appropriately and fully protected from adverse consequences, if any, that may arise from the Merger. The Commission, therefore, finds and concludes that Regulatory Condition No. 32a should be adopted for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witness Hager and Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff witnesses testified that proposed Regulatory Condition No. 23 states that costs and credits associated with the Catawba agreements will result in no harm to North Carolina retail customers. This condition provides that the assignment or allocation of costs to the North Carolina retail jurisdiction will not be adversely affected by virtue of the agreements between Duke Power and the Catawba Joint Owners.

CUCA's proposed Regulatory Condition No. 23 replaces "be adversely affected by the manner and amount of recovery of electric system costs from the Catawba Joint Owners as a result of the agreements between Duke Power and the Catawba Joint Owners" with "result in an Effect [as defined by CUCA] adverse to the interest of Duke Power's Carolina retail ratepayers due to the manner and amount of recovery of electric system costs from the Catawba Joint Owners as a result of the agreements between Duke Power and the Catawba Joint Owners."

Having rejected use of the term "Effect," as defined by CUCA, in the Regulatory Conditions, the Commission concludes that Regulatory Condition No. 23 is already clear and rejects CUCA's proposed revision.

The Public Staff witnesses also testified that proposed Regulatory Condition Nos. 25 through 27 protect North Carolina retail ratepayers from potential negative effects of the merger by ensuring that direct merger costs and any costs associated with commitments made by Duke Power or imposed on Duke Power are not flowed through to Duke Power's cost of service for ratemaking purposes.

Regulatory Condition No. 25 proposed by Duke Energy and the Public Staff excludes direct expenses associated with costs to achieve the Merger from Duke Power's retail cost of service for ratemaking purposes and provides that any capital costs must be shown by Duke Power to benefit North Carolina retail customers before they may be included. This condition also provides that, if a one-year rate decrement is approved, Duke Power may spread the impact evenly over five years, but must note the amount expensed as a footnote to its ES-1 Reports.

CUCA's proposed Regulatory Condition No. 25 provides that the impact of the rate decrement may be evenly spread over "the savings period upon which the decrement was based."

After careful consideration, the Commission concludes that Regulatory Condition No. 25 should be modified to include the following additional language:

> If the merger is not consummated, neither the cost of any termination payment nor the receipt of a termination payment between Duke Energy and Cinergy shall be allocated to Duke Power's books. Nor shall Duke Power's North Carolina retail customers otherwise bear any direct expenses or costs associated with a failed merger.

The modification adopted and required by the Commission with respect to Regulatory Condition No. 25 ensures that there will be no adverse impact on the rates charged to Duke Power's North Carolina retail ratepayers and that the ratepayers are sufficiently protected from potential costs that may result if the Merger fails to be consummated.

Furthermore, as discussed below, the Commission has adopted Duke Energy's offer of a one-year rate decrement in the amount of $117,517,000, and the Commission also finds it reasonable and appropriate to adopt Duke Energy's proposal to allow the Company to spread the impact evenly over five years for NCUC ES-1 reporting purposes. Accordingly, CUCA's proposed revision to Regulatory Condition No. 25 is rejected.

Proposed Regulatory Condition Nos. 26 and 27 ensure that any commitments to Duke Power's wholesale customers in connection with the Merger will not decrease the bulk power revenues to be shared in Docket No. E-7, Sub 751, or increase North Carolina retail fuel costs or cost of service.

CUCA's proposed Regulatory Condition No. 26 provides that if "one or more" commitments to Duke Power's wholesale customers "have an Effect that is adverse to the interest of Duke Power's North Carolina retail customers," including but not limited to the effects listed, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes.

Having rejected use of the term "Effect," as defined by CUCA, in the Regulatory Conditions, the Commission concludes that Regulatory Condition No. 26 is already clear and rejects CUCA's proposed revision. The Commission further concludes that the addition of "one or more" is equally unnecessary, as "commitments" is already plural.

As explained by the Public Staff witnesses, proposed Regulatory Condition No. 28 provides that any acquisition adjustment that results from the merger will be excluded from Duke Power's utility accounts and will not affect Duke Power's North Carolina retail electric rates and charges. CUCA's proposed revision would replace "affect Duke Power's North Carolina retail rates and charges" with "have an Effect that is adverse to the interests of Duke Power's North Carolina retail ratepayers," but the proposed revision is rejected.

The Public Staff witnesses testified that proposed Regulatory Condition Nos. 29 and 30 provide that Duke Energy and its affiliates will take all steps reasonably necessary to hold Duke Power's North Carolina retail ratepayers harmless from any effects of the merger and that North Carolina retail ratepayers will be protected from current and prospective liabilities of Cinergy.

CUCA's proposed revision to Regulatory Condition No. 29 would replace "effects of the Merger, including" with "each and every Effect of the Merger that is adverse to Duke Power's North Carolina retail ratepayers, including but not limited to." This revision is rejected for the reasons given above with respect to other conditions.

None of the parties took issue with Regulatory Condition No. 30. The Commission notes, however, that this condition effectively addresses the concern expressed by Environmental Defense with respect to the impact of Cinergy's environmental compliance costs on North Carolina retail ratepayers.

The Commission, therefore, finds and concludes that the Commission-approved Regulatory Conditions will effectively protect Duke Power's North Carolina retail customers from other impacts of the Merger on cost of service for ratemaking purposes.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witness Hager and Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff testified that Regulatory Condition No. 34 provides that Duke Power and its affiliates and nonpublic utility operations would be bound by the Code of Conduct approved in this proceeding. Other than several specific revisions proposed by CUCA, no party took exception to the Code of Conduct.

The Commission notes that approval of this condition by the Commission would impose a Code of Conduct on Duke Power that is significantly broader and more restrictive than the Code approved in Docket No. E-7, Sub 694. The most substantive revisions are the expansions of the Code of Conduct to explicitly incorporate certain standards, or revised to provide more specific instructions, with respect to (a) nonpublic utility operations, (b) separation of Duke Power operations from affiliate operation, (c) disclosure of Confidential Systems Operation Information, (d) joint marketing and the use of Duke Power's name or logo in non-utility advertising, (e) intangible benefits compensation, if appropriate, (f) shared services, (g) disclosure of Customer Information to affiliates and non-affiliates, (h) exchange of goods and services between Duke Power and the other

Utility Affiliates of new Duke Energy, (i) joint coal purchases between Duke Power, PSI, and ULH&P, and (j) demonstration of the reasonableness and prudence of any permitted acquisition of natural gas, other fuel, or purchased power by Duke Power from an affiliate or nonpublic utility operation.

The specific revisions proposed by CUCA to the Code of Conduct include the following: (1) substantial revisions to the definition of Fully Distributed Cost, (2) the explicit exclusion of goods and services that are subject to sale or purchase at market based rates from Section III.D.3.(c), and (3) the inclusion in Section III.E.3 of a requirement that a competitive bidding process be used.

The Public Staff and Duke Energy also proposed an amendment to the definition of Fully Distributed Cost and proposed that the definitions in the Conditions and the Code be the same. The definition they proposed in the Attachment A filed with their proposed orders is as follows:

> **Fully Distributed Cost:** All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (1) the return on common equity utilized in determining such cost of capital for each good and service supplied by or from Duke Power shall equal the return on common equity authorized by the Commission in Duke Power's most recent general rate case proceeding, and (2) the cost of capital for each good and service supplied to Duke Power shall not exceed the overall cost of capital authorized by the Commission in Duke Power's most recent general rate case proceeding.

The definition proposed by CUCA would require the cost of capital for each good and service supplied by or from Duke Power to equal the overall cost of capital, which would not allow current debt costs to be used. The Commission concludes that CUCA's definition unduly complicates the matter, particularly considering that the cross-subsidization concern upon which CUCA's revisions are based is prohibited by the Code of Conduct.

With respect to CUCA's proposed revision of Section III.D.3.(c), the Commission concludes that the proposed change is unnecessary. "Customer," as defined in the Code, is any Duke Power retail customer, which means the provision is only applicable to retail tariffs. Similarly, CUCA's proposed change to Section III.E.3 is unnecessary. Similar provisions which have been approved by the Commission for other utilities have not required that competitive bidding be used. Finally, CUCA's proposed changes to reflect its defined terms "Effect" and "Requesting Intervenor" have been discussed and rejected elsewhere in this order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witness Caldwell and Public Staff witnesses Cox, Farmer, and McLawhorn.

Duke witness Caldwell testified that, based upon estimates as to income, assets, and market capitalization, the new Duke Energy would be one of the top five electric businesses in the United States if the Merger is approved. He further testified that Duke Power would benefit from new Duke Energy's financial strength and access to financial markets and that Duke Power would itself retain the ability and financial strength to obtain financing on its own, subject to any needed regulatory approvals.

He further testified that, historically, Duke Energy's Duke Power division has had strong cash flow and financial stability and the Merger will have no adverse impact on this position. Post-Merger, Duke Power will be a separate first-tier subsidiary under new Duke Energy. As a separate subsidiary, Duke Power's credit risk will be rated separately from that of new Duke Energy and its other subsidiaries, with the structure in place after the Merger potentially improving the credit standing of Duke Power as a stand-alone company. The financial ability of new Duke Energy and Duke Power, he testified, would support Duke Power's ability to provide reliable service to its North Carolina ratepayers.

Witness Caldwell further testified that each operating company, including Duke Power, would have its own distinct capital structure for both accounting and ratemaking purposes, with Duke Power issuing its own debt and/or receiving equity contributions from new Duke Energy as needed. He also testified that the operating companies' dividend payout amounts would be consistent with each operating company maintaining an adequate cash position and that all debt issued by new Duke Energy and its other subsidiaries would be non-recourse to Duke Power.

The Public Staff's testimony described the general finance conditions as follows: Regulatory Condition Nos. 35 through 37 provide for the tracking of cost of capital details so that the Public Staff may evaluate and propose various capital structure components and cost rates for regulatory purposes. Regulatory Condition No. 38 provides a means for adjusting long-term debt cost if Duke Power's long-term debt is adversely affected by the Merger. Regulatory Condition No. 39 addresses the redemption of Duke Energy preferred stock. Regulatory Condition Nos. 40 and 41 require Duke Power's long-term debt securities to be associated with its utility operations and capital requirements and contain procedural and informational requirements for Duke Power's and Duke Energy's financings. Regulatory Condition No. 42 clarifies that other conditions do not restrict the Commission's right to adjust Duke Power's cost of capital for securities associated with the Merger. Finally, because Merger-related risks could affect Duke's cost of debt or common stock, Regulatory Condition No. 53 makes all of the cost of capital conditions in the stipulated conditions applicable to, and prevents any Merger risks from affecting, Duke Power's determination of the maximum allowable AFUDC rate, the rate of return applied to any deferred accounts, and the other purposes listed in the condition.

With respect to Regulatory Condition Nos. 43 through 52, the Public Staff testified that they are intended to address the loss of PUHCA 1935 protections by providing some protections to Duke Power and its ratepayers from any financial risks caused by the creation of a holding company and affiliated dealings. To this end, Regulatory Condition No. 43 establishes as a target an investment grade debt rating for Duke Power and requires prompt notice and action if Duke Power's debt rating falls to the lowest level considered investment grade. Regulatory Condition No. 44 (originally No. 47) provides that both Duke Power and new Duke Energy are obligated to ensure that Duke Power's operations are adequately funded. Regulatory Condition No. 45 (originally No. 44) and No. 46 (originally No. 45) set parameters for distributions from Duke Power to Duke Energy and for Duke Power's investment in non-regulated assets, respectively.

The Public Staff further testified that the annual report required in Regulatory Condition No. 47 (originally No. 46) will provide some perspective concerning Duke Energy's investments in

Exempt Wholesale Generators and generation assets in foreign countries. Requirements related to short-term and long-term debt financings are set out in Regulatory Condition No. 48. The composition of Duke Energy's Board of Directors is addressed in Regulatory Condition No. 49. Condition No. 50 sets forth notification requirements for Duke Power if it makes certain regulated or non-regulated investments. Regulatory Condition No. 51 requires notification in the event of a default of an obligation or a bankruptcy that is material to Duke Energy. Finally, an annual report is required in Regulatory Condition No. 52 to provide information on Duke Power, Duke Energy, and certain significant affiliates, including current organization, non-regulated investments, risk assessments, capital structure, market capitalization, protective measures, and shared personnel.

With respect to Duke Energy's proposed Utility Money Pool Agreement (Utility MPA), as shown in Exhibit 2 to witness Caldwell's testimony, the Public Staff stated that it was concerned that it includes participants that currently or potentially prospectively are not utility companies. Tri-State Improvement Company is a development company for CG&E and should be excluded from the Utility MPA. Because the generation assets of CG&E may become completely unregulated after 2008, the Public Staff recommended that Duke Power should be required to obtain Commission approval to continue to participate in the Utility MPA if CG&E is still a participant. These concerns were addressed in Regulatory Condition No. 48. The Public Staff recommended that Duke Power be required to re-file the Utility MPA in accordance with Regulatory Condition No. 48.[1] To address the reporting requirements in G.S. 62-169, the Public Staff recommended that Duke Power file monthly reports for months that it initiates a transaction under the Utility MPA. Such reports should include the following for each transaction: date of transaction, borrowing or lending activity, counterparty, amount, date of maturity, interest rate, brief explanation for interest rate, and associated expenses.

Neither CUCA witness O'Donnell nor CIGFUR III witness Phillips specifically addressed Regulatory Condition Nos. 35 through 42 and No. 53, although CIGFUR III witness Phillips did offer some comments on the ring-fencing conditions, which are summarized below.

On rebuttal, Duke witness Caldwell testified that, with the exit of Duke Energy from substantially all of the DENA business, any risk to Duke Power from unregulated operations would be substantially reduced. The formation of the holding company and the presence of Duke Power as a stand-alone subsidiary will provide additional protection to insulate Duke Power from any potential risks associated with the unregulated businesses. He also noted that, as part of the Stipulation, Duke Energy has committed to Regulatory Condition Nos. 35 through 53, which specify new Duke Energy's obligations with regard to finance and corporate governance and include an annual report requirement that will include, among other things, an assessment of the risk associated with significant affiliates of Duke Power. He also pointed out that the Commission is able to protect customers from risk through its statutory authority with regard to ratemaking. In his opinion, there are no additional significant risks to customers from the unregulated operations of new Duke Energy and any potential risks are more than offset by the existing regulatory framework and the settlement and conditions with the Public Staff.

In response to a question from the Commission with respect to whether any of the conditions would make it difficult for Duke Power to operate in the manner that he thought necessary, witness Caldwell testified that he was comfortable with all of the conditions associated with the financings (Regulatory Condition Nos. 35 through 53). In addition, witness Caldwell stated that, if the

[1] Duke Energy filed its revised Utility Money Pool Agreement on February 14, 2006.

Commission approved the proposed Merger, what North Carolina would have with Duke Power would be nothing but a utility, except for ancillary things like holding property for future utility use.

For purposes of discussion, this order divides Regulatory Condition Nos. 35 through 53 into two groups based upon their purpose: (1) Regulatory Condition Nos. 35 through 42 and Condition No. 53, which provide the usual kinds of protections the Commission has approved in the past to protect a utility's ratepayers from adverse financial impacts of a proposed Merger, and (2) Regulatory Condition Nos. 43 through 52, which are "ring-fencing" measures designed to replace the loss of PUHCA protections.

(1) General Financial Protections

With respect to the more general financial protections provided by Regulatory Condition Nos. 35 through 42 and No. 53, the Commission concludes, based upon the foregoing, that they will effectively insulate Duke Power's ratepayers from any increases in cost of capital and other risks related to the Merger. Specifically, Regulatory Condition No. 36 requires Duke Energy and Duke Power to keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. The purpose of this condition is to ensure that the components of the cost of capital can be isolated so that ratepayers can be held harmless from the effect of any Merger-related risks in this regard. Similarly Regulatory Condition No. 38 protects ratepayers from the possibility of higher borrowing costs if the Merger were to have a negative impact on Duke Power's credit rating. It provides that to the extent that debt ratings are adversely affected by a downgrade due to the Merger, a replacement cost rate will be utilized to prevent Duke Power's ratepayers from paying any increased costs.

Regulatory Condition No. 39 is solely a reporting requirement allowing the Commission to track the source of the funds used to execute the redemption of current Duke Energy preferred stock.

The first part of Regulatory Condition No. 42 ensures that no prior orders of the Commission with respect to Duke Energy issuances are affected by the conditions. The second part continues the Commission's long-standing expressed right to review and adjust a utility's cost of capital for ratemaking purposes to account for the effects of the securities-related transactions associated with the Merger.

Finally, because Merger-related risks could affect Duke's cost of debt or common stock, Regulatory Condition No. 53 makes all of the cost of capital conditions in the stipulated conditions applicable to, and prevents any Merger risks from affecting, Duke Power's determination of the maximum allowable AFUDC rate, the rate of return applied to any deferred accounts, and the other purposes listed in the condition.

Most of the foregoing conditions have been approved in numerous prior merger proceedings and have not been controversial. Other than Regulatory Condition No. 41, CUCA's specific proposed revisions to the foregoing conditions are solely to include the defined terms "Requesting Intervenor" and "Effect" and to add "adverse to the interests of Duke Power ratepayers." These proposed revisions have been rejected previously in this order and are rejected with respect to these conditions for the same reasons.

CUCA proposed to delete Regulatory Condition No. 41 as unnecessary because its proposed amendments to Regulatory Condition No. 2 provide that Duke Energy (the holding company) shall be deemed a public utility for purposes of Article 8 of Chapter 62 and G.S. 62-111 and that it waives all federal and constitutional challenges, thus making Regulatory Condition No. 41 unnecessary.

Under Regulatory Condition No. 41, new Duke Energy is required to file an annual financing plan, including details about the types of security, an estimate of cost rates, the amount of the proceeds, a brief description of the purpose for the issue, and the amount of proceeds, if any, that might flow to Duke Power. This condition further provides that Duke Energy may proceed with equity issuances upon the filing of the plan, but cannot issue debt until 30 days after the plan has been filed. Specifics as to procedures by which the Commission can determine if any debt issuance requires approval pursuant to Chapter 62 also are provided.

The Commission notes that this condition does not remove any Commission authority. It merely facilitates review by the Commission of new Duke Energy's financing plans. The Commission retains the authority to treat new Duke Energy as a public utility by virtue of G.S. 62-3(23)(c) if it makes the necessary finding that new Duke Energy's affiliation with Duke Power, with regard to a proposed equity issuance, affects Duke Power's rates or service.

More importantly, the Commission does not need absolute authority with respect to equity issuances by new Duke Energy. The Commission's major concern in this regard with a holding company is that it will become too highly leveraged and its worsened financial state will have a negative impact upon the utility. The ability to determine without challenge whether proposed debt issuances will affect Duke Power and to take appropriate action, again without challenge, if the Commission finds that they do is sufficient authority in this regard. In addition, as discussed more fully below, if the Commission were concerned that Duke Power had become overly leveraged, it could require new Duke Energy to take action, such as infusing equity into Duke Power, pursuant to Regulatory Condition No. 44 (originally filed as No. 47). Finally, the Commission does not need to control new Duke Energy's equity issuances for purposes of determining Duke Power's capital structure for ratemaking purposes because the Commission has full authority to determine the appropriate capital structure for such purposes.

The Commission concludes that the revisions proposed by CUCA should be rejected. The protections provided by the Commission-approved conditions in conjunction with the insulating effects of the legal separation of the holding company and the utility operations that will occur as a result of the Merger will effectively protect Duke Power's ratepayers.

(2) Ring-Fencing Conditions

As described by the Public Staff in its testimony, Regulatory Condition Nos. 43 through 52, the so-called ring-fencing conditions, are intended to address the loss of PUHCA 1935 protections by providing some protections to Duke Power and its ratepayers from any financial risks caused by the creation of a holding company. On cross-examination, the Public Staff testified that Regulatory Condition Nos. 43 and 47 (No. 47 is now No. 44) are sufficient to protect Duke Power in the event of a problem with the parent.

CIGFUR III witness Phillips testified that the conditions are not adequate to protect the utility against the parent company leaning on it during times of stress. In response to questions from the

Commission, witness Phillips referenced a case involving the financial difficulties of CMS Energy (CMS) resulting from investments in other countries. He testified that, despite its pledge not to let those activities affect its regulated subsidiary, he believed that the Michigan Commission ended up having to grant a rate increase to the regulated subsidiary of CMS because of concerns about bankruptcy.

The repeal of PUHCA 1935 presents numerous issues because of the loss of its consumer protections. It was designed to control holding companies and prevent abusive affiliated transactions; cost misallocations; financial abuse, such as draining the utility of cash and using it for collateral; and diversification into non-core, risky businesses. With the repeal of PUHCA 1935, none of these federal limitations and protections remain in effect.

Section 7 of PUHCA 1935, 15 U.S.C. § 79g, provided for extensive regulation of the use of securities by holding companies and their subsidiaries. In addition, § 12 of PUHCA 1935, 15 U.S.C. § 79l, prohibited holding companies and their subsidiaries from borrowing and from receiving an extension of credit, or an indemnification, from a public utility in the same holding company system. By virtue of PUHCA 1935, using a utility's assets or revenue streams as collateral for holding company or affiliate loans, using the utility as a "cash cow" to make excessive dividend payments, thereby depriving the utility of working capital, and diversifying by investing in unrelated businesses and increasing the riskiness of the utility were all prohibited. These types of restrictions, along with limitations on future acquisitions and mergers, typically are called ring-fencing measures. Such measures tend to be a major topic of discussion at the state level and within NARUC given the repeal of PUHCA 1935 effective February 8, 2006.

Ring-fencing can be defined as the legal walling off of certain assets or liabilities within a corporate family, including the creation of a new subsidiary to protect (i.e., ring-fence) specific assets from creditors.[1] Ring-fencing measures are used to insulate a regulated utility from the potentially riskier activities of unregulated affiliates. From a debt rating agency perspective, ring-fencing mechanisms are techniques used to isolate the credit risks of one company from the risks of affiliate companies. Concurrent use of numerous ring-fencing measures, including regulatory, financial, structural, and operational restrictions, is considered to be the most effective way to separate risk.[2]

According to Fitch Ratings, the holding company structure itself aids in the construction of a strong ring fence.[3] Thus, Duke's proposed separation of its regulated utility operations into a separate company, rather than continuing to operate the utility as a division of the parent company, is an effective ring-fencing measure separate and apart from the other measures discussed subsequently herein.

The Sarbanes-Oxley Act of 2002 is viewed as protection for a utility's captive customers in that it requires audit committee independence, chief executive officer and chief financial officer certification of the accuracy and truth of financial filings, enhanced financial disclosure, and criminal fraud accountability. These requirements, when coupled with appropriate ring-fencing measures,

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[1] Commission Staff Analysis of Ring-Fencing Measures for Investor-Owned Electric and Gas Utilities, Maryland Public Service Commission Staff, February 18, 2005.

[2] Bonelli, Sharon and Lapson, Ellen, Ratings Linkage within U.S. Utility Groups, Fitch Ratings Global Power/North America Special Report, April 9, 2003.

[3] Id., at p. 3.

should provide for a transparent environment that will enable the Commission and others to monitor the activities of Duke Power, new Duke Energy, and its unregulated subsidiaries.

Generally speaking, a key difficulty in establishing ring-fencing measures is fashioning a response that meets all of the goals but does not unnecessarily inhibit the operations of the utility and its relationships within a holding company structure. Possible solutions include (a) capital structure requirements (often a minimum percentage of equity), (b) dividend restrictions, (c) restrictions on unregulated investments, including some control over future acquisitions and mergers, whether unregulated or not, (d) prohibitions or at least control of utility asset sales, (e) collateralization requirements, (f) working capital restrictions, (g) prohibitions on inter-family loans, (h) maintenance of stand-alone bonds, (i) independence of board members, (j) bankruptcy protection, and (k) credit rating separation. These possible solutions are discussed separately below.

(a) Capital structure requirements. Conditions related to capital structure requirements can be couched in terms of a minimum percentage of equity being maintained. The Oregon Public Utility Commission, when it approved the acquisition of Portland General Electric (PGE) by Enron Corporation in Order No. 97-196 on June 4, 1997, required that PGE maintain a 48% equity ratio. Kentucky's stipulation and order approving the present Merger require that ULH&P maintain a capital structure with a minimum of 35% equity.

Prescribing a specific equity ratio is problematic for a number of reasons. A relatively high minimum equity ratio increases the cost of financing ongoing business operations. Debt is generally less expensive, within leverage limits, because debt usually has a significantly lower cost than equity. In addition, a utility with a higher equity ratio than its parent or unregulated affiliates creates the potential for the parent and affiliates to benefit from the utility's higher equity ratio by increasing their debt levels while maintaining the same debt rating. On the other hand, an equity minimum that is too low can also cause higher costs to be incurred because a more highly leveraged company is a higher risk. The optimal solution is for the equity ratio to be high enough for the utility to maintain a solid investment grade debt rating, but no higher.

Regulatory Condition No. 44 (originally proposed as No. 47) addresses these concerns. This condition provides that new Duke Energy and Duke Power shall ensure that Duke Power has sufficient access to equity and debt capital to enable Duke Power to adequately fund and maintain its current and future generation, transmission, and distribution systems and otherwise meet the service needs of its customers at a reasonable cost. This condition imposes on new Duke Energy both the obligation to infuse sufficient equity and debt capital into Duke Power to adequately fund its current and future operations and the obligation that such funding be at a reasonable cost. This allows the ratio of equity to debt to fluctuate from time to time depending upon industry trends and issues, but it requires that the costs to ratepayers always be reasonable.

The protections afforded by this condition are further enhanced by the requirement in Regulatory Condition No. 43 that Duke Power operate its business with the intention of maintaining an investment grade rating and a requirement that, in the event its debt rating falls to the lowest investment grade level, it provide immediate notice to the Commission and the filing of a plan 45 days later regarding the steps it intends to take to maintain and improve its debt rating.

Finally, part 4 of the report required by Regulatory Condition No. 52 requires Duke Power to provide a description of the actual capital structure of Duke Power and each "Significant Affiliate" and to describe new Duke Energy's and Duke Power's goals for Duke Power's capital structure and plans for achieving those goals.

(b) Dividend restrictions. Conditions related to dividend restrictions need to strike a balance between not discouraging investors while preventing the siphoning off of utility funds to the detriment of the utility. Regulatory Condition No. 45 (formerly No. 44) requires cumulative distributions paid by Duke Power to new Duke Energy subsequent to the Merger to be limited to (i) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (ii) any future earnings recorded by Duke Power subsequent to the Merger. This is very similar to the provision in the Kentucky stipulation and order that provides that ULH&P will pay dividends only out of retained earnings.

(c) Restrictions on unregulated investments. Significant investments in unregulated assets can obviously create greater risks for the parent and its subsidiaries. Six of the conditions are designed to ameliorate these risks. One of these, Regulatory Condition No. 46 (formerly No. 45), prohibits Duke Power from investing in a non-regulated utility asset or any non-utility business venture exceeding $50 million dollars in purchase price or gross book value to Duke Power (except for land held for future franchise use) until after it has provided 30 days' advance notice to the Commission.

Regulatory Condition No. 50 requires new Duke Energy to notify the Commission of any intended investment in a regulated or non-regulated business representing five percent or more of new Duke Energy's market capitalization. Because investments in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) are generally considered to be riskier than many other types of investments, Regulatory Condition No. 47 (formerly No. 46) requires new Duke Energy to provide an annual report summarizing its investments in EWGs and FUCOs.

While not included in the "Finance/Corporate Governance" section of the conditions, Regulatory Condition Nos. 41 and 54 can be considered to be ring-fencing measures. Regulatory Condition No. 41 requires that an annual financing plan be filed, including descriptions of all financings that new Duke Energy reasonably believes may occur during the calendar year. This enables the Commission to determine if any proposed debt financings could affect Duke Power sufficiently for approval under North Carolina law to be required. Similarly, Regulatory Condition No. 54 provides a mechanism by which the Commission can determine if a merger or acquisition proposed by new Duke Energy is likely to affect Duke Power, thereby necessitating the filing of an application for approval.

Finally, the annual report required by Regulatory Condition No. 52 requires Duke Power to (1) identify all "Significant Affiliates" that are considered to constitute non-regulated investments and provide each company's total capitalization, the percentage it represents of new Duke Energy's total non-regulated investment, and the percentage it represents of new Duke Energy's total investments, and (2) provide an assessment of the risks that each unregulated "Significant Affiliate" could pose to Duke Power based upon the current business activities of those affiliates and any contemplated significant changes to those activities.

(d) Prohibitions on utility asset sales. As previously discussed in this order, Regulatory Condition No. 3 applies to the transfer by Duke Power to any entity, affiliated or not, of the control of, operational responsibility for, or ownership of utility assets with a gross book value in excess of $10 million. It requires that notice be given and that any contract effectuating the proposed transfer contain language protecting the Commission's authority. In addition, Regulatory Condition No. 9 prohibits any agreement and all filings with the FERC that alter Duke Power's obligations with respect to the conditions, absent explicit approval of the Commission. Finally, Regulatory Condition No. 10 requires notice to the Commission 30 days prior to any filing with the FERC of any agreement, tariff, or other document or any proposed changes, amendments, modifications, or supplements to any such document that have the potential to affect Duke Power's cost of service or otherwise affect its rates or service.

(e) Collateralization restrictions. Chapter 62 regulates the extent to which a utility can guarantee or be used as collateral for affiliate debt. G.S. 62-160 prohibits a public utility from pledging its faith, credit, moneys, or property for the benefit of any holder of its stocks or bonds or any other business interest with which it may be affiliated without making application to the Commission and obtaining its permission by order. G.S. 62-161 prohibits a public utility from assuming any liability or obligation as lessor, lessee, guarantor, indorser, surety or otherwise with respect to any other person unless and until the Commission, after investigation, authorizes by order such issue or assumption. Because explicit written approval is required, conditions prohibiting utility guarantees and requiring parent company debt to be non-recourse to the utility are not necessary.

(f) Working capital restrictions. As discussed above, Regulatory Condition No. 44 (formerly No. 47) imposes on new Duke Energy the obligation to infuse sufficient equity and debt capital into Duke Power to adequately fund its current and future operations, and Regulatory Condition No. 45 (formerly No. 44) imposes limits on the amount of cumulative distributions that can be paid by Duke Power to Duke Energy.

(g) Prohibitions on inter-family loans. Regulatory Condition No. 48 requires Duke Power to borrow short-term funds through the financial markets or through the Utility Money Pool Agreement (Utility MPA) approved by the Commission, which prohibits loans through the Utility MPA being made to, and borrowings through the Utility MPA being made by, new Duke Energy and Cinergy Corp. In addition, it requires Duke Power to acquire its long-term debt funds through the financial markets and prohibits its borrowing from, and lending to, on a long-term basis, new Duke Energy or any of its other affiliates.

(h) Maintenance of stand-alone bonds. Regulatory Condition No. 40 requires Duke Power to identify as clearly as possible long-term debt (of more than one year duration) that it issues in connection with its regulated utility operations and capital requirements or to replace existing debt. In addition, Regulatory Condition No. 48 requires that Duke Power acquire its long-term debt funds through the financial markets, and have all of the debt it acquires through the financial markets rated under its own name, to the extent it is feasible to obtain a debt rating.

(i) Independence of board members. Regulatory Condition No. 49 requires new Duke Energy to comply with the New York Stock Exchange Listing Standards with respect to the composition of its Board of Directors. These standards require listed companies to have a majority of independent directors on their boards of directors, which increases the quality of board oversight and lessens the possibility of conflicts of interest. See Corporate Governance Standard 303A.01.

(j) Bankruptcy protection. Regulatory Condition No. 51 requires Duke Power to notify the Commission of a default if (1) an affiliate of Duke Power experiences a default of an obligation that is material to Duke Energy or (2) files for bankruptcy, and such bankruptcy is material to new Duke

Energy. This notification must be made in advance, if possible, or as soon as possible, but not later than ten days, from the default. In addition, part 5 of the annual report required by Regulatory Condition No. 52 requires Duke Power to provide a complete description of all protective measures (other than those provided for by the conditions adopted in this case) in effect between Duke Power and any of its affiliates and a description of how each measure operates, including the mitigation of Duke Power's exposure in the event of a bankruptcy proceeding of any affiliates.

(k) Credit rating separation. To the extent ring-fencing measures are viewed as effective or enforceable, credit rating agencies may not consolidate a utility subsidiary with its parent for debt rating purposes. Regulatory Condition Nos. 35 through 52, as a package, should be sufficient to justify a separate credit rating for Duke Power.

With respect to CIGFUR III witness Phillips' use of a CMS case in Michigan to criticize the proposed ring-fencing conditions, a review of the Michigan Commission's order in Case No. U-13730, dated October 14, 2004, reveals that the "pledge" apparently made by CMS was in filings made pursuant to § 33(a)(2) of PUHCA 1935, 15 U.S.C. 79z-5b, with respect to investments in FUCOs, and that the "pledge" was a representation that the investments would not have a detrimental effect on the regulated utility. Interestingly, in this regard, the Michigan Commission initiated a show cause proceeding in 2003 (Case No. U-13860) because CMS had not filed the application required by PUHCA 1935 before investing in a FUCO.

In neither of these cases does it appear that the Michigan Commission had previously imposed significant conditions or taken other official actions, particularly with respect to specific limits on the payment of dividends and the imposition on the parent of a specific, enforceable obligation to provide adequate funds at a reasonable cost to the utility. As a result, this situation does not cast doubt on the adequacy of the ring-fencing conditions proposed in this proceeding. Similar conditions did not fail in the CMS situation; there were very few, if any, comparable conditions. In addition, the witness for CIGFUR III acknowledged on cross-examination that he did not know if Duke Power would have to get permission from the Commission to loan money to an affiliate and conceded that the conditions make progress.

CUCA's specific proposed revisions to these conditions include (1) adding the defined term "Requesting Intervenor," (2) adding "alone or collectively in a calendar year" to Regulatory Condition Nos. 45 and 50, and (3) changing "shall" to "may" in Regulatory Condition No. 48. The Commission has rejected the first two with respect to other conditions and again rejects these revisions. With respect to Regulatory Condition No. 48, the Commission notes that the purpose of the term "shall" was to prohibit Duke Power from borrowing short-term funds from affiliates. If "shall" were changed to "may," further revisions to the condition would be necessary to prohibit Duke Power from borrowing short-term funds from new Duke Energy or other affiliates. This proposed revision also is rejected.

The foregoing conditions as a group provide very comprehensive ring fencing protections. In addition, a comprehensive report is required by Regulatory Condition No. 52 to allow the Commission to gather relevant information into one report, which will allow the Commission to act more promptly if it becomes necessary to take measures to protect Duke Power. Nevertheless, the Commission is of the opinion that two supplemental conditions need to be added in the general area of financial requirements.

The first of these conditions concerns the appropriate capital structure for use by Duke Power in preparing its quarterly NCUC ES-1 Reports to the Commission. This condition, which has been memorialized as Regulatory Condition No. 37a, in essence, provides that Duke Power shall, following consummation of the Merger, begin transitioning to its actual capital structure for purposes of calculating and reporting its actual North Carolina retail jurisdictional earnings to the Commission. In particular, this condition sets forth general guidelines for Duke Power to follow in the phase-in process and establishes a time certain by which Duke Power shall have transitioned to exclusive use of its actual capital structure for purposes of its quarterly NCUC ES-1 Reports. Regulatory Condition No. 37a also contains certain informational reporting requirements. The Commission has determined that this condition is needed in consideration of the change in the organizational structure of the regulated corporate entity, including the change in its actual capital structure, which will result upon consummation of the Merger, and in consideration of the overall objective associated with the Commission's ES-1 reporting requirement.[1]

The second supplemental condition concerns the carry-forward, without adjustments, of certain Duke Energy balance sheet account balances to Duke Power's balance sheet following the Merger, that is, in particular, account balances of the following nature: regulatory liability; deferred credit, including deferred income tax; reserve; valuation; and over-accrued liability accounts, if any, applicable and/or reasonably attributable to Duke Energy's regulated electric utility operations which existed prior to consummation of the Merger. This condition also contains provisions which are intended to help ensure that funds, if any, distributed to Duke Energy after consummation of the Merger that are attributable to payments and distributions made by its regulated electric utility operations prior to the Merger are, where appropriate, promptly distributed to Duke Power. This condition has been memorialized as Regulatory Condition No. 53a.

The Commission is of the opinion that Regulatory Condition No. 53a is needed in consideration of certain aspects of modern-day accounting theory, including certain generally-accepted principles, practices, and procedures through which it is implemented. The art of accounting, and in particular the periodic reporting of net income and/or operating income, inherently involves the use of estimates, assumptions, and judgments. Estimates are most often not realized in an absolute sense and assumptions and judgments do not always turn out to be entirely correct, notwithstanding their having been made with the best of intentions and employing state-of-the-art techniques. Thus, it is not at all unusual for a level of cost recorded in one period to be adjusted in a subsequent period, and such adjustments may, in certain instances, be of material consequence.

In consideration of the foregoing and generally speaking, the primary purpose of Regulatory Condition No. 53a is this: to the extent, if any, certain regulated electric utility accounts have been overstated prior to the Merger, this provision is intended to help ensure that adjustment for such overstatement will be made to, and reflected in, regulated electric utility accounts following the Merger. Thus, in consideration of (a) the foregoing, (b) the change in the corporate ownership of the regulated electric utility following the Merger, and (c) the need to ensure that Duke Power's North Carolina retail customers are not disadvantaged in any way by the Merger, the Commission has

[1] Generally speaking, with regard to jurisdictional utilities who are subject to rate base, rate-of-return regulation, the purpose of the ES-1 reporting requirement is to allow the Commission to obtain meaningful information on an ongoing basis which will allow the Commission to monitor the financial viability of the reporting companies, including assessment of certain standard measures of their profitability and consequently, in certain respects, thereby allowing the Commission to gain insight into the appropriateness of their existing rates and charges.

determined that the present condition is warranted and that it should be implemented as a regulatory condition in addition to those proposed by Duke Energy and the Public Staff.

The Commission, therefore, finds and concludes that Commission-approved Regulatory Condition Nos. 35 through 53a will effectively address known and potential risks and concerns related to finance, corporate governance, and certain other matters of a financial nature arising from the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff witnesses testified that proposed Regulatory Condition No. 54 provides for Commission approval of future proposed mergers by Duke Power and notification of further proposed mergers involving Duke Energy or other affiliates.

Regulatory Condition No. 54, as proposed by Duke Energy and the Public Staff, addresses both business combinations involving Duke Power and those involving other entities within the Duke Energy holding company family. With respect to Duke Power, this condition provides that an application for approval pursuant to G.S. 62-111(a) will be filed at least 180 days before the closing of the proposed transaction. With respect to the other entities, it establishes a procedure to enable the Commission to determine, before the fact, whether a proposed transaction is reasonably likely to affect Duke Power so as to require approval pursuant to the statute.

In considering whether to approve the Regulatory Conditions proposed by Duke Energy and the Public Staff, the Commission is influenced by regulatory conditions approved in other dockets, most recently those approved for Progress by order issued October 27, 2004, in Docket No. E-2, Sub 844, as well as by factors specific to this case. The Commission notes that Regulatory Condition No. 33 approved in Docket No. E-2, Sub 844, requires the filing of advance notification of a proposed transaction and the filing of an application for approval of a transaction believed to have an effect on utilities 180 days prior to the closing date. Progress' condition further provides for a "demonstration of no effect" on utilities, a 45-day comment period, and a ruling by the Commission as promptly as possible. If the Commission does not agree with the demonstration, closing is prohibited until the transaction has been approved. Thus, Progress' condition recognizes that not all business combinations within the holding company family will implicate G.S. 62-111(a).

Regulatory Condition No. 54(b), as proposed by Duke Energy and the Public Staff, takes the same general approach as Progress' condition. Unlike Progress' condition, however, the advance notification requirement in Regulatory Condition No. 54(b) is proposed to be limited to business combinations with a transaction value exceeding five percent of the market capitalization of new Duke Energy. In addition, unlike Progress' condition, Regulatory Condition No. 54(b) explicitly provides that the entity in question may proceed with the transaction if no order has been issued at the end of the notice period, although it will be subject to any fully adjudicated Commission order on the matter, including a requirement to file an application and potential ultimate denial of approval to enter into the proposed transaction.

The Commission raised questions during oral argument concerning the use of the defined term "Effect on Duke Power's Rates or Service" in proposed Regulatory Condition 54(b), suggesting that the condition be revised to conform to the language in G.S. 62-111(a), which reads "affecting any public utility." A question was also raised as to whether subsection (d) should be revised to clarify that the 180-day notice requirement in subsection (a) does not also apply if the Commission determines that approval is required pursuant to the statute. The Further Revised Regulatory Conditions proposed by Duke Energy and the Public Staff attempted to address these concerns.

CUCA initially proposed to revise Regulatory Condition No. 54 to require Duke Energy to file an application for approval pursuant to G.S. 62-111(a) of any business combination involving a member of the holding company family, whether or not the transaction has been determined to affect Duke Power. In Exhibit 1 attached to its brief, CUCA subsequently argued that Regulatory Condition No. 54 "should be deleted in virtually its entirety because it appears to unduly limit the Commission's merger jurisdiction." CUCA further argued "that the application of a 5% threshold to a $60 billion company such as [new Duke Energy] would allow a merger of up to $3 billion without regulatory scrutiny."

After careful consideration, the Commission is of the opinion that the general framework set forth in Regulatory Condition No. 54, as proposed by Duke Energy and the Public Staff, is a reasonable and appropriate way of enabling the Commission to exercise its authority and responsibility under G.S. 62-111(a) while recognizing Duke Energy's right to assert in a timely manner that jurisdiction does not lie in a specific case. Regulatory Condition No. 54(a) is clarified, however, to require Duke Power to file in advance an application pursuant to G.S. 62-111(a) for approval of any proposed transaction "by or affecting" Duke Power. Thus, Duke Power shall proceed to file an application for any transaction that it concedes is subject to the jurisdiction of the Commission pursuant to G.S. 62-111(a). To require the filing of an application in each and every case, as advocated by CUCA, would not only burden the Commission's docket unnecessarily but also attempt to impermissibly expand the Commission's statutory authority under G.S. 62-111(a) to include approval of proposed business combinations not affecting Duke Power. Regulatory Condition No. 54(b) is revised to incorporate as subsections the applicable procedures proposed by Duke Energy and the Public Staff in sections 54(c) through 54(e). Under Regulatory Condition No. 54(b), Duke Energy is only required to provide 90-day advance notice to the Commission of transactions involving Duke Energy, other affiliates, or the nonpublic utility operations which (1) Duke Energy believes do not affect Duke Power and would not, therefore, be subject to the Commission's jurisdiction pursuant to G.S. 62-111(a) and (2) exceed a threshold transaction value. The Commission agrees with CUCA, however, that the threshold proposed by Duke Energy and the Public Staff is too high, and shall require Duke Energy to file advance notice pursuant to Regulatory Condition No. 54(b) of any transaction which involves Duke Energy, other affiliates, or the nonpublic utility operations and which has a transaction value exceeding $1 billion.

The Commission, therefore, finds and concludes that the Regulatory Conditions, as modified and approved herein, will effectively enable the Commission to exercise its jurisdiction over business combinations involving Duke Power or other members of the Duke Energy holding company family following the Merger. The Commission reserves the right to act on its own motion with regard to any advance notice filed by Duke Power regardless of whether objections are filed by any other party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff testified that Regulatory Condition Nos. 55 through 57 address (1) notice requirements before Duke Power transfers functions or employees, (2) continuing Commission review of the holding company structure, and (3) discussions between Duke Power and the Public Staff about significant changes and developments affecting Duke Power or new Duke Energy. Regulatory Condition No. 58 addresses filing requirements for the Tax Sharing Agreement as well as any plans to consolidate employee benefits plans and other similar agreements.

Regulatory Condition No. 55 requires Duke Power to file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, employees, rights, obligations, assets, or liabilities from Duke Power to an affiliate to the extent such transfers potentially would have a significant effect on Duke Power's public utility operations. Regulatory Condition No. 56 provides that the benefits, costs, and associated risks of the Merger and the operation of Duke Power under a holding company structure shall continue to be subject to Commission review and subject to the Commission's authority to order lawful modifications to the structure or operations of Duke Energy and Duke Power's other affiliates. Finally, Regulatory Condition No. 57 requires Duke Power to meet and consult with, and provide requested relevant data to, the Public Staff, at least semiannually through 2010, unless there is agreement that no meeting is necessary, regarding plans for significant changes in Duke Power's or new Duke Energy's organization, structure, and activities; the expected or potential impact of such changes on Duke Power's retail rates, operations, and service; and proposals for assuring that such plans do not adversely affect Duke Power's North Carolina retail electric customers.

CUCA proposed several specific revisions with respect to these conditions. With respect to Regulatory Condition No. 55, CUCA proposed to increase the required advance notice from 30 to 75 days. The Commission concludes that this proposal should be rejected. The provision, as proposed by Duke Energy and the Public Staff, represents a reasonable balance between allowing Duke Power to operate its business and providing sufficient time for parties to raise concerns. CUCA also proposed to revise Regulatory Condition No. 55 to state that it would be deemed applicable to a transfer or a series of transfers involving more than 50 employees in a calendar year. The Commission rejects this proposed change also. Again, the condition, as proposed by Duke Energy and the Public Staff, represents a reasonable balance between allowing Duke Power to operate its business and providing sufficient time for parties to raise concerns. Additionally, the transfer of 50 employees may be too few or too many, depending upon what functions are involved. The other changes proposed by CUCA to these four conditions have already been rejected in other parts of this order.

The Commission, therefore, finds and concludes that Commission-approved Regulatory Condition Nos. 55 through 58 will effectively address known and potential risks and concerns related to structure and organization arising from the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff testified that Regulatory Condition No. 59 describes the procedures to be followed for advance notices with respect to the various conditions. As revised, it clearly sets forth the procedures that are to be followed with respect to all filings that are required pursuant to the Regulatory Conditions. Parties to this docket may file a request in Docket No. E-7, Sub 795A within 30 days of the date of this order to be made parties to that docket and to be served with copies of any filings made pursuant to Regulatory Condition No. 59(a)(i) that do not involve advance notices.

CUCA proposed that Regulatory Condition No. 59(a)(ii) be revised to require Duke Power to "state prominently on the first page of such advance notice that it is filed 'pursuant to Condition 59 of the Regulatory Conditions set forth in Docket No. E-7, Sub 795.'" The Commission rejects this proposal because this subsection already requires sufficient identifying information to be provided in the cover sheet for an advance notice.

CUCA also proposed to revise Regulatory Condition No. 59(b)(ix) to provide that, as a general rule, Duke Power shall bear the burden of proof in proceedings pursuant to Regulatory Condition No. 59. The Commission rejects this proposed revision because it is inconsistent with the conclusion reached by the Commission in its September 11, 2002 order in Docket No. E-2, Sub 753A. In that order, the Commission rejected the Public Staff's argument that the party protesting the subject of the advance notice should be required to show sufficient grounds for a hearing, but that the burden of proof on the merits should be borne by the utility. The Commission concluded that the party filing the objection should bear the burden of proof if the Commission schedules a hearing on the objection. This same procedure is set forth in Regulatory Condition No. 59, as filed by the Public Staff and Duke Energy.

However, the Commission will require that Regulatory Condition No. 59(b)(viii) be revised to add a new second sentence which reads as follows: "The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue." Under the procedures set forth in Regulatory Condition No. 59, when Duke Power files a 30-day advance notice, the Public Staff or any other party has 15 days within which to file an objection. The Public Staff then has two weeks to place the matter on a Commission Staff Conference Agenda. Finally, if the Commission has not issued an order at the end of the advance notice period, Duke Power may proceed with the activity to be undertaken, but shall be subject to any fully-adjudicated Commission order on the matter. Since the procedure under Regulatory Condition No. 59 could take almost the entire advance notice period, leaving the Commission with little or no time to investigate the matter which is the subject of the advance notice, the Commission shall require that Regulatory Condition No. 59 be further revised, as specifically described herein, to prevent Duke Power from proceeding with any activity to be undertaken until the Commission reaches a decision. Furthermore, the Commission reserves the right to act on its own motion with regard to any advance notice filed by Duke Power regardless of whether objections are filed by any other party.

The Commission concludes that Regulatory Condition No. 59, as approved herein, will provide appropriate and effective procedures for advance notices and other filings arising from the Merger or this order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witnesses Shaw and Rogers and Public Staff witnesses Cox, Farmer, and McLawhorn.

Witness Shaw testified that the proposed Merger will directly enhance Duke Power's ability to serve its customers by providing even greater depth of human resources experience to customer service. For example, the broader employee base will provide all retail customers access to greater resources in the event of severe weather or emergency outages. Witness Shaw stated that quality of service should also improve by giving Duke Power access to the best practices of well-run utilities in the Cinergy group. In addition, Duke Power customers will continue to have the same local presence of, and access to, the utility that they have come to expect.

Witness Rogers testified that, like Duke Power, Cinergy's operating utilities share a commitment to service and satisfaction, commitments that are reflected in recent rankings and awards such as those given by J.D. Powers and Associates.

Regulatory Condition No. 60 proposed by Duke Energy and the Public Staff provides that Duke Power will continue to implement and further its commitment to providing superior utility service, will make every effort to incorporate best practices of utilities in the Cinergy group in Duke Power's operations, and will work with the Public Staff to monitor service quality. This condition further commits Duke Power to advise the Commission at least annually for a period of five years on the adoption and implementation of best practices following the Merger. In addition, Further Revised Regulatory Condition No. 44 requires both Duke Energy and Duke Power to ensure that Duke Power has sufficient access to capital to be able to maintain its facilities and otherwise meet the service needs of its customers.

The Commission rejects the suggestion of CIGFUR III that the term "superior" in Regulatory Condition No. 60 might be defined to strengthen the condition. As noted by Duke Energy and the Public Staff, this term has been used in similar conditions, without objection, in various proceedings. As the term appears to be well understood and accepted, the Commission believes no definition is necessary.

The Commission also rejects CUCA's proposal that Duke Power be required to work with "each Requesting Intervenor" in addition to the Public Staff to monitor service quality; however, the Commission expects Duke Power to work with all of its customers to monitor and improve service quality to them individually.

The Commission, therefore, finds and concludes that the Commission-approved Regulatory Conditions will effectively ensure that Duke Energy and Duke Power maintain a commitment to customer service following the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff testified that Regulatory Condition Nos. 61 and 62 provide that Duke Power, under any tax sharing agreement, will not seek to recover any tax cost that exceeds Duke Power's tax liability calculated on a stand-alone basis and that Duke Power shall share in appropriate tax benefits associated with Duke Energy Shared Services. Additionally, the Public Staff testified that it had discussed the Tax Sharing Agreement with Duke Energy and recommended that the agreement be re-filed clarifying certain terms and allocation methodologies.[1]

None of the parties took issue with Regulatory Condition Nos. 61 and 62. The Commission concludes that the approved conditions will effectively ensure that Duke Power's North Carolina retail customers are protected from any adverse effects of a tax sharing agreement and that they will receive an appropriate portion of income tax benefits associated with Duke Energy Shared Services.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff witnesses testified that proposed Regulatory Condition Nos. 63 and 64 address the continuation of the current ratemaking treatment of Nantahala's hydroelectric generation resources as well Nantahala's separate rates and financial information.

Regulatory Condition No. 63 provides that retail customers in Duke Power's Nantahala area will continue to receive the benefits of Nantahala's historical hydroelectric generating resources. Regulatory Condition 64 provides that, until the Commission orders otherwise, the rates charged Nantahala's retail customers will continue to be based on Nantahala's own cost of service, Nantahala's purchased power costs will continue to be determined in accordance with the Duke – Nantahala Interconnection Agreement, and stand-alone Duke Power and Nantahala financial information will continue to be provided.

None of the parties took issue with Regulatory Condition Nos. 63 and 64. The Commission finds and concludes that the Commission-approved Regulatory Conditions will effectively preserve the benefits of Nantahala's historical hydroelectric resources and cost of service for Nantahala's retail customers following the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27 - 32

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Cox, Farmer, and McLawhorn.

The Public Staff witnesses testified that Regulatory Condition Nos. 65 through 71 proposed by Duke Energy and the Public Staff address miscellaneous matters such as continued access to books and records of Duke Energy, applicability of prior Commission orders, the Commission's

[1] Duke Energy filed its revised Tax Sharing Agreement on March 3, 2006.

statutory authority, and the ability of Duke Power and its affiliates to request waivers from the conditions.

Regulatory Condition No. 65 provides that the Commission will continue to have access to the books and records of Duke Power and other members of the Duke Energy holding company family, in accordance with North Carolina law. Regulatory Condition No. 66 ensures that all Duke Power books and records will be made available in Charlotte, North Carolina.

None of the parties took issue with Regulatory Condition Nos. 65 and 66. The Commission finds and concludes that these Commission-approved Regulatory Conditions will effectively ensure that the Commission and the Public Staff continue to have access to the books and records of Duke Power and members of the Duke Energy holding company family in accordance with North Carolina law.

Regulatory Condition No. 67 provides that all prior orders of the Commission applicable to Duke Energy, Duke Power, and Nantahala will remain applicable to Duke Power after the Merger unless superseded by Commission order. To enable the Commission to determine which of the regulatory conditions previously approved remain in effect, this condition requires Duke Energy to file for comment a list of conditions imposed in Docket Nos. E-7, Subs 557, 596, 694, and 700, which have not been superseded by the Regulatory Conditions.

None of the parties took issue with Regulatory Condition No. 67. The Commission finds and concludes that the Commission-approved Regulatory Conditions will appropriately recognize the continuing effect of prior Commission orders.

Regulatory Condition No. 68, as proposed by Duke Energy and the Public Staff, provides as follows:

> These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions either (a) constitute specific exercises of the Commission's authority, (b) provide mechanisms that enable the Commission to determine in advance the extent of its authority and jurisdiction over proposed activities of and transactions involving Duke Power, Duke Energy Corporation, other Affiliates or Nonpublic Utility Operations, or (c) protect the Commission's jurisdiction from federal preemption and its effects. Pursuant to these conditions, Duke Power, Duke Energy Corporation, and other Affiliates waive certain of their federal rights as specified in these Regulatory Conditions, but do not otherwise agree that the Commission has authority other than as provided for in Chapter 62. Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy Corporation, Duke Power, and its Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina law or the other grounds listed in G.S. 62-94(b).

CUCA proposed certain changes to Regulatory Condition No. 68 in order to prevent such Condition from "undermining the efficacy of all other conditions."

The Commission finds good cause to approve Regulatory Condition No. 68 as filed and to deny CUCA's proposed changes for the reason that such changes are unnecessary. Regulatory Condition No. 68 does not, in any way, undermine the efficacy of any of the other Commission-approved Regulatory Conditions. This Regulatory Condition does not restrict or detract from the Commission's statutory authority or otherwise subtract from the benefits and protections offered by the other Regulatory Conditions. Therefore, the Commission finds and concludes that the Commission-approved Regulatory Conditions clearly and accurately describe their effect on the Commission's statutory authority and Duke Energy's rights under state and federal law.

Regulatory Condition No. 69 provides that these Regulatory Conditions are not intended to and do not purport to impose legal obligations on entities in which Duke Energy does not directly or indirectly have a controlling voting interest.

None of the parties took issue with Regulatory Condition No. 69. The Commission finds and concludes that the Commission-approved Regulatory Conditions will appropriately clarify that there is no intent to impose legal obligations on entities not subject to control by new Duke Energy.

Regulatory Condition No. 70 proposed by Duke Energy and the Public Staff provides that entities subject to the conditions may request waivers if exigent circumstances in a particular case justify such. CUCA's proposed Regulatory Conditions omit this provision, and the record indicates that CUCA believes relief should be sought pursuant to G.S. 62-80 rather than through a waiver request.

G.S. 62-80 authorizes the Commission upon notice and opportunity to be heard to rescind, alter, or amend an order or decision made by it. While the language of the statute is quite broad, it allows the Commission to reconsider or rehear a matter when, for example, it appears that a decision was based on a misapprehension of the facts. In the Commission's experience, circumstances that may justify a waiver of a regulatory condition are not such as to require reconsideration of the condition in its entirety. Rather, a waiver procedure simply recognizes the impossibility of anticipating and addressing all circumstances where the letter of a condition may apply but the spirit of the condition would warrant an exception. The Commission, therefore, finds and concludes that the Commission-approved Regulatory Conditions will appropriately allow requests for waivers of any aspect of the conditions under exigent circumstances.

Regulatory Condition No. 71 provides that the Regulatory Conditions will become effective only upon the closing of the Merger. The Commission finds and concludes that the Commission-approved Regulatory Conditions will appropriately become effective only upon closing of the Merger. The Commission notes, however, that if the Merger is not approved, Duke Energy will continue to be subject to conditions and code of conduct provisions approved in previous dockets and many of the protections and benefits secured by the Commission-approved Regulatory Conditions will not be realized until another day.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The Revised Regulatory Conditions proposed by Duke Energy and the Public Staff include a new condition which makes it clear that the conditions are not intended to affect the rights of parties to this docket with respect to participation in subsequent proceedings. The Commission believes that this new Regulatory Condition No. 72 is sufficient to protect the legitimate rights and interests of intervenors with respect to all of the other conditions on an ongoing basis.

In its proposed conditions, CUCA included the following defined term:

> **Requesting Intervenor:** An intervenor in this proceeding, provided that the intervenor signs a confidentiality agreement to protect the confidentiality of any proprietary information of Duke Energy Corporation, Duke Power, or any Affiliate, to the extent the disclosing company reasonably deems a confidentiality agreement to be necessary.

CUCA proposed to insert this term in a number of the Regulatory Conditions proposed by Duke Energy and the Public Staff. While the proposed definition would appear to include the Public Staff, some of CUCA's proposed Regulatory Conditions refer to "the Public Staff and each Requesting Intervenor," and the Commission therefore assumes that the Public Staff is not included.

The Commission finds and concludes that the Commission-approved Regulatory Conditions appropriately recognize the effect of the Regulatory Conditions on the rights of parties to this docket with respect to participation in subsequent proceedings, that the definition of the term "Requesting Intervenor" proposed by CUCA is not necessary, and that adopting CUCA's proposal might, in fact, introduce unneeded confusion into the operation of the Regulatory Conditions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

The evidence supporting this finding of fact is contained in the testimony of Duke Energy witness Hieronymus. This finding of fact is uncontroverted.

Witness Hieronymus presented and explained a detailed market power analysis that he conducted, and from which he concluded that the proposed merger will have no adverse effect on competition in the markets in which Duke Energy and Cinergy conduct business. There was no cross-examination or rebuttal of witness Hieronymus' study or conclusions, nor did any other witness address the effect of the Merger on competition or market power.

The Commission, therefore, finds and concludes that the Merger presents no known risk of adverse competitive effects within the jurisdiction of the Commission or concerns of increased market power within Duke Power's service territory.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35 - 37

The evidence supporting these findings of fact is contained in the testimony of Duke Energy witnesses Flaherty and Hager, CIGFUR III witness Phillips, CUCA witness O'Donnell, and Public Staff witnesses Cox, Farmer, and McLawhorn.

Regulatory Condition No. 73[1] as proposed by Duke Energy and the Public Staff provides that Duke Power would share $117,517,000 or 42% of the net merger savings assignable to North Carolina with its retail customers. This sharing is in addition to any fuel-related savings associated with the Merger that will flow through the annual fuel charge adjustment.

[1] The number for this Regulatory Condition changed from 72 to 73 based on the revisions filed by the Public Staff on January 27, 2006. The corresponding Commission-approved Regulatory Condition is also numbered 73.

CIGFUR III witness Phillips testified that Duke Energy's proposal to keep all of the unregulated savings and share 42% of the regulated savings amounts to keeping 86% and giving up only 14% of total savings related to the Merger. With respect to the sharing of net merger savings, witness Phillips recommended a base rate reduction of $78.8 million annually based on normalized net savings during the third year, excluding one-time costs. He further recommended that the reduction be allocated 45% to residential customers, 45% to industrial customers, and 10% to commercial customers based on the differences between Duke Power's rates in North Carolina and South Carolina.

CUCA witness O'Donnell initially testified that a proxy for the risk to ratepayers of accounting misrepresentations involving affiliate transactions would be the average annual pre-tax effect of accounting irregularities that occurred in 1998, 1999, and 2000 as identified in the 2002 Grant Thornton report or approximately $41,300,000 a year. In order to compensate ratepayers for the larger risks related to the Merger, Duke Energy should share 50% of the ten-year estimated net merger savings. In his rebuttal testimony, witness O'Donnell recommended that the $112,517,000 one-time rate reduction recommended by the Public Staff, if approved, be allocated exclusively to manufacturers in Duke Power's North Carolina territory.

Duke Energy witness Flaherty testified that the use of a ten-year view of cost savings realization to determine the level of savings to be distributed to customers would be inappropriate because it introduces a level of uncertainty and additional complexity into determination of the level of sharing. He stated that it is not the predictability in saving estimation that should determine the time period over which savings should be viewed. Rather, it is the ability to adequately determine the financial and operating position of the merged companies that defines the time frame to be utilized. Witness Flaherty further testified that adopting a period longer than five years would be difficult to accept without providing for adequate protection against the possibility of adverse events which have been prone to occur given the nature, degree, and pace of change with this industry. He stated that the use of a longer time period would imply that there will be no subsequent opportunities for the Commission to revisit the level of savings sharing in a future rate proceeding when better information is available about ongoing costs, financial performance and other external influences that can affect required rate levels. Furthermore, he testified that, in his experience, a shorter time period is typically used where an up-front savings sharing will be determined.

The Commission does not find good cause to base the decision in this case on ten-year cost savings projections as advocated by CUCA.[1] As noted above, the Commission's merger filing requirements call for estimates of savings "over a specified period (e.g., three to five years) following consummation of the merger. . ."[2] Accordingly, the Commission finds good cause to deny CUCA's proposed revisions to Regulatory Condition Nos. 25, 72, and 73 to utilize ten-year estimated savings in furtherance of its position. With respect to Condition No. 72, however, the Commission agrees in concept with CUCA's proposed revision to include language used in South Carolina, but believes that the language proposed by Duke Energy and the Public Staff is more appropriate. The Commission notes that Regulatory Condition No. 24 provides that any party may, without objection, seek the inclusion of cost savings that may be realized as a result of the Merger in future rate proceedings.

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[1] Nor has the Commission made a finding regarding the validity and correctness of the Company's five-year Cost-Benefit Analysis. See footnote 21.

[2] See Order Requiring Filing of Analyses entered in Docket No. M-100, Sub 129 on November 2, 2000 (Decretal Paragraph 2.a).

The Commission agrees with Duke Energy witness Hager that the reliance of CIGFUR III on rate disparities between North and South Carolina, standing alone,[1] is contrary to North Carolina law. See State ex rel. Corporation Comm'n v. Cannon Mfg. Co., 185 N.C. 17, 28, 116 S.E. 178, 185 (1923): "[T]he Corporation Commission [now Utilities Commission] in this State is empowered and directed to make reasonable and just rates as applied to the distribution and sale of power in this State and not otherwise, and such power cannot be directly controlled or weakened by conditions existent in other states, either from the action or nonaction of official bodies there, or the dealings between private parties. To hold otherwise would, in its practical operation, be to withdraw or nullify the powers that the statute professes to confer and should not for a moment be entertained." See also State ex rel. Utilities Comm'n v. Lee Tel. Co., 263 N.C. 702, 709, 140 S.E.2d 319, 325 (1965): "When a company operates in two or more states, the operations are treated as separate businesses for the purpose of rate regulation."

Moreover, the Commission rejects CUCA's argument that the ratepayers are somehow at risk in amounts exceeding $400 million over the next ten years because of potential accounting misrepresentations involving affiliate transactions. The Commission addressed the basis for this argument in 2002 by approving a Settlement Agreement between Duke Energy and the Commission Staff and the Staff of the Public Service Commission of South Carolina in an order that withstood challenge on appeal. State ex rel. Utilities Comm'n v. Carolina Utility Customers Association, Inc., 163 N.C. App. 1, 592 S.E.2d 277 (2004). The Settlement Agreement provides that the Staffs "desire to formally and positively resolve all matters within the scope of the accounting review without further controversy" and that "[h]aving reached resolution of this matter, it is the intention of the parties to move forward in a positive fashion without further controversy." This was the Commission's desire and intent as well. The Commission also rejects as unreasonable and inappropriate the specific rate reduction proposals advocated by CIGFUR III and CUCA, including the testimony regarding those proposals offered by their respective witnesses. The Commission-approved one-year rate decrement in the amount of $117,517,000 is based on a careful consideration of the totality of the facts in this case, including all of the other Commission-approved Regulatory Conditions. It is not unreasonable or unfair to Duke Power since it is the level of rate reduction in dollars offered by the Company as a principal part of its proposal to gain approval of the Merger. It is also generally consistent with the position taken by the Public Staff as to the appropriate amount of the one-year rate decrement in total dollars which should accrue to the benefit of Duke Power's North Carolina retail customers. In sum, $117,517,000 is a fair and reasonable amount by which to reduce rates by a rate decrement in this case, considering in particular the totality of the Conditions imposed by the Commission on the Merger.

Duke Power proposes to share 42% ($117,517,000) of the five-year estimated net merger savings amount of $279,841,000 assignable to its North Carolina retail customers. Public witness Lancaster requested additional funding for economic development and educational programs established through the sharing of net revenues from bulk power sales that was approved by the Commission in Docket No. E-7, Sub 751. The Public Staff witnesses recommended a one-year across-the-board decrement to Duke Power's rates in the amount of $112,517,000, with the remainder distributed as follows: $2,000,000 for Duke Power's Share the Warmth, Cooling Assistance, and Fan-Heat Relief programs; $2,000,000 for conservation and energy efficiency programs (to be submitted to the Commission for approval); and $1,000,000 for NC GreenPower.

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[1] Evidence comparing the rates of different utilities "is not competent or proper in the absence of evidence showing the comparative costs and conditions under which the respective companies operate." State ex rel. Utilities Comm'n v. Gas Co., 254 N.C. 734, 740 (1961).

The Public Staff witnesses further stated, however, that if the Commission wished to direct a portion of the savings to worker training through the Community College Grant Fund, the Public Staff would have no objection and would recommend that the $2,000,000 for conservation and energy efficiency programs be reduced accordingly. Duke Energy took no position on this issue.

After careful consideration, the Commission concludes that the Merger should be approved subject to the following conditions as set forth in Commission-approved Regulatory Condition Nos. 73 through 76:

(1) Duke Power shall implement a one-year across-the-board decrement to rates for the benefit of its North Carolina retail customers in the amount of $117,517,000, rather than $112,517,000 as advocated by the Public Staff.[1] This decision is literally consistent with the proposed language of Regulatory Condition No. 73, which provides, in pertinent part, that "Duke Power shall share with its North Carolina retail customers $117,517,000 . . . in a manner to be determined by the Commission." If customers receive a one-year rate reduction of only $112,517,000, with the remaining $5,000,000 being allocated to other uses, Duke Power's North Carolina retail customers will not in fact receive the full benefit of the exact "sharing" required by the Duke Energy and Public Staff proposed Regulatory Condition No. 73, i.e., $117,517,000. Furthermore, the Commission rejects as unreasonable CUCA's suggestion that any rate reduction be limited to a single class of customers. All customers will bear the risks associated with the Merger, and it only follows that all customers should share in the quantifiable benefits.

(2) Any fuel-related savings associated with the Merger shall be flowed through to Duke Power's North Carolina retail customers pursuant to G.S. 62-133.2.

(3) Duke Power shall contribute $12,000,000 to various energy- and environmental-related and economic- and educationally-beneficial programs, said funds to be distributed as follows: $6,000,000 to Duke Power's Share the Warmth, Cooling Assistance, and Fan-Heat Relief programs; $2,000,000 for conservation and energy efficiency programs (to be submitted to the Commission for approval)[2]; $2,000,000 to the Community College Grant Fund; and $2,000,000 to NC GreenPower. These contributions shall be made by Duke Power on or before June 30, 2006. Such contributions shall not be charged to Duke Power's regulated utility operations, but shall be borne by the Company's shareholders.

(4) The Commission will, in 2007, initiate an investigation[3] pursuant to G.S. 62-130(d), 62-133, and 62-136(a) to determine whether Duke Power's existing rates and charges are unjust and

[1] In so ruling, the Commission has made no finding or determination as to either the reasonableness of Duke's specific proposal to share 42% of the Company's five-year estimated net merger savings amount of $279,841,000 assignable to its North Carolina retail customers, the propriety of the determination and apportionment thereof, or the validity and correctness of the Company's Cost-Benefit Analyses. Thus, the Commission's decision to accept Duke's offer to implement a one-year rate reduction in the amount of $117,517,000 should not be viewed as a precedent in future merger cases, particularly on issues related to the reasonableness of the percentage of net merger savings proposed to be shared with consumers or the validity of the Cost-Benefit Analysis employed by the utility to estimate net merger savings.

[2] Duke Power, the Public Staff, and the Attorney General shall confer and jointly develop a list of appropriate and effective conservation and energy efficiency programs and shall submit their recommendations to the Commission for approval not later than 45 days from the date of this Order.

[3] This investigation will be undertaken as a condition to regulatory approval of the Merger and has been memorialized as Regulatory Condition No. 76.

unreasonable and, as part of this investigation, will require Duke Power to either (a) file a general rate case (including prefiled testimony and exhibits) in North Carolina pursuant to G.S. 62-137 or (b) show cause in the form of prefiled testimony and exhibits why the Company's existing rates and charges should not be found unjust and unreasonable[1] The Merger at issue in this docket and the Commission-approved Regulatory Conditions adopted herein are extremely complex and will have significant impact on the post-merger operations and regulation, including surveillance, of Duke Power. Upon consummation of the Merger, the organizational structure of Duke Power will be substantially altered; Duke Power will become, for the first time, a stand-alone operating company and a first-tier subsidiary within a holding company structure. Therefore, consummation of the Merger will constitute a compelling and very specific factor that warrants a general rate investigation for Duke Power so that the Commission can ensure that (a) the ongoing rates charged by Duke Power are in fact just and reasonable and (b) customers receive the actual, achieved benefits of Duke Power's post-merger operations to the maximum extent possible.[2] Nevertheless, in so ruling, the Commission notes that it has made no determination that the rates currently being charged by Duke Power are in fact unjust and unreasonable. To the contrary, that is why the Commission will allow Duke Power, in the first instance, to either file a general rate case (including prefiled testimony and exhibits) in North Carolina pursuant to G.S. 62-137 or show cause why the Company's existing rates and charges are not unjust and unreasonable.

Regulatory Condition No. 74 provides that Duke Power's North Carolina retail customers will receive the benefit of "Most Favored Nation" status with regard to the percentage sharing of net merger savings among the states of Kentucky, Ohio, South Carolina, and Indiana.

The Commission has reviewed the orders of other state commissions filed by Duke Energy and the assessment of those orders/settlement proposals filed by the Public Staff. Based on this review, the Commission concludes that none of the sharing arrangements agreed to and/or approved in other states invokes the "Most Favored Nation" provision in Regulatory Condition No. 74.[3] That

[1] The test period for this proceeding will be the twelve-month period ending December 31, 2006, with appropriate adjustments. Duke Power will be required to make its filing, including a Rate Case Information Report - NCUC Form E-1, not later than June 1, 2007. Any rate changes proposed by Duke Power should be proposed to become effective on January 1, 2008. To the extent the $117,517,000 one-year rate decrement flowed through by Duke Power to its North Carolina retail customers is deferred, with plans or provisions for amortization over future periods pursuant to Regulatory Condition No. 25, no portion of such amount, including amortization thereof, will be eligible for recovery as a component of Duke Power's North Carolina retail rates set prospectively following consummation of the Merger. In particular, no allowance for same will be included in the test-year cost of service developed for purposes of the general rate case proceeding to be instituted pursuant to this Regulatory Condition; nor will any portion of such amount be recoverable from Duke Power's North Carolina retail ratepayers by means of a rate rider or otherwise. Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. This investigation will be consolidated with the investigation and hearing the Commission is required to undertake for Duke Power pursuant to G.S. 62-133.6(d) and (f) to review the Company's environmental compliance costs.

[2] Indeed, the Commission views this provision as integral to the safeguards implemented herein to ensure that Duke Power's North Carolina retail ratepayers are protected to the maximum extent possible from potential negative consequences, if any, which may arise from approval of the Merger.

[3] Pursuant to the order entered in this docket on December 20, 2005, parties have until Monday, April 3, 2006, to file comments on the report filed by Public Staff on March 23, 2006, wherein the Public Staff set forth its evaluation of the Indiana Utility Regulatory Commission's recent order approving the Settlement Agreement. If any comments are filed, the Commission will take appropriate action.

provision, which is identical to the "Most Favored Nation" provisions in the other states, is limited to the percentage of net merger savings that will be shared with retail ratepayers. It does not include other benefits and commitments, which may or may not be quantifiable and may or may not be relevant to North Carolina. Likewise, none of the Regulatory Conditions imposed by the Commission in this case will trigger any of the "Most Favored Nation" provisions in the other states and the Commission has been careful to adopt no Condition which will trigger any of those provisions.[1]

Furthermore, the Commission is satisfied that the benefits of the Merger to be received by Duke Power's North Carolina retail ratepayers are at least equal to those to be received by retail ratepayers in the other states and in many respects are superior. To the Commission's knowledge, no other state commission has imposed specific conditions giving it the same opportunity to determine in advance the extent of its statutory jurisdiction over activities of utility affiliates or the protections against federal preemption set forth in the Commission-approved Regulatory Conditions.

The Commission, therefore, finds and concludes that the Commission-approved Regulatory Conditions and Code of Conduct will effectively ensure that Duke Power's North Carolina retail customers will receive an appropriate share of the benefits resulting from the Merger.

CONCLUSIONS OF LAW

The Commission concludes that (1) the Commission-approved Regulatory Conditions and Code of Conduct, (2) the one-year across-the-board decrement to rates for the benefit of Duke Power's North Carolina retail customers in the amount of $117,517,000[2], (3) the $12,000,000 contribution to various energy- and environmental-related programs to be made by Duke Power, and (4) the Commission-initiated 2007 Duke Power rate investigation are sufficient to ensure that the Merger will have no adverse impact on the rates and service of Duke Power's North Carolina retail ratepayers; that Duke Power's retail ratepayers are protected as much as possible from potential costs and risks resulting from the Merger; that there are sufficient benefits from the Merger to offset the potential costs and risks; and that the proposed business combination between Duke Energy and Cinergy is justified by the public convenience and necessity.

Accordingly, the Commission finds good cause to approve Duke Energy's application to enter into a business combination with Cinergy, provided that Duke Energy shall file a statement in this docket notifying the Commission that the Company accepts and agrees to all of the terms, conditions, and provisions of this order +and the Commission-approved Regulatory Conditions and Code of Conduct.

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[1] This conclusion is supported by representations by Duke Power's counsel at the January 18, 2006 oral argument (Tr. pp. 74-80). The Commission notes that the one-year rate decrement in the amount of $117,517,000 ordered by the Commission is equivalent and equal to the exact dollar amount offered by Duke Power based upon its proposal to share 42% of the Company's five-year estimated net merger savings amount assignable to its North Carolina retail ratepayers.

[2] Duke Power shall, not later than Friday, April 7, 2006, make an appropriate filing to implement this rate decrement in conjunction with its pending fuel adjustment proceeding in Docket No. E-7, Sub 805.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke Energy's Application to enter into a business combination with Cinergy is approved, provided that Duke Energy shall, not later than Friday, March 31, 2006, file a statement in this docket notifying the Commission that the Company accepts and agrees to all of the terms, conditions, and provisions of this order and the Commission-approved Regulatory Conditions and Code of Conduct attached hereto as Attachments A and B, respectively, and incorporated herein;

2. That the Commission will take further action, if necessary, as contemplated by Regulatory Condition No. 16 following the issuance of a FERC decision on rehearing with respect to FERC Docket No. EC05-103-000; however, notwithstanding anything in this paragraph, unless changed by a subsequent Commission order, this order constitutes final approval of the Application in this docket;

3. That, consistent with the provisions of this order, Duke Power, the Public Staff, and the Attorney General shall confer and jointly develop a list of appropriate and effective conservation and energy efficiency programs and shall submit their recommendations to the Commission for approval not later than 45 days from the date hereof; and

4. That parties to this docket may file a request in Docket No. E-7, Sub 795A within 30 days of the date of this order to be made parties to that docket and to be served with copies of any filings made pursuant to Regulatory Condition No. 59(a)(i) that do not involve advance notices.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Bb032406.01

ATTACHMENT A

REGULATORY CONDITIONS
DOCKET NO. E-7, SUB 795

A. DEFINITIONS

For the purposes of these Regulatory Conditions, the terms listed below shall have the following definitions:

Affiliate: Duke Energy Corporation and any business entity, other than Duke Power, of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy Corporation. For purposes of these Regulatory Conditions, Duke Energy Corporation and any business entity so controlled by it are considered to be Affiliates of Duke Power.

Affiliate Contract: Any contract or agreement (a) between and among any of the Affiliates if such contracts are reasonably likely to have an Effect on Duke Power's Rates or Service, or (b) to which both Duke Power and any Affiliate are parties. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, and wholesale power sales agreements and agreements involving financings and asset transfers and sales.

Catawba Joint Owners: The North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency No. 1, Piedmont Municipal Power Agency, and Saluda River Electric Cooperative, Inc. For purposes of these Regulatory Conditions, Duke Power is not included in the definition of Catawba Joint Owners.

Commission: The North Carolina Utilities Commission.

Customer: Any retail electric customer of Duke Power, including those served under the Commission-approved rates for Nantahala Power and Light.

Duke Energy Corporation: The current holding company parent of Duke Power and any successor company.

Duke Energy Shared Services: Duke Energy Shared Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to Duke Power, Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations of Duke Power, singly or in any combination.

Duke Power: Duke Power Company, LLC, the business entity, wholly owned by Duke Energy Corporation, that holds the franchises granted by the Commission to provide Electric Services within the North Carolina service territories of Duke Power and Nantahala Power and Light, and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Effect on Duke Power's Rates or Service: When used with reference to the consequences to Duke Power of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, or sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, and standby service.

FERC: The Federal Energy Regulatory Commission.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (1) the return on common equity utilized in determining such cost of capital for each good and service supplied by or from Duke Power shall equal the return on common equity authorized by the Commission in Duke Power's most recent general rate case proceeding, and (2) the cost of capital for each good and service supplied to Duke Power shall not exceed the overall cost of capital authorized by the Commission in Duke Power's most recent general rate case proceeding.

Market Value: The price at which property, goods, and services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: The mergers, the conversion of Duke Energy Corporation into a limited liability company, the restructuring transactions, and all other transactions contemplated by the Agreement and Plan of Merger between Duke Energy Corporation and Cinergy Corp.

Nonpublic Utility Operations: All business operations engaged in by Duke Power involving activities (including the sales of goods or services) that are not regulated by the Commission, nor otherwise subject to public utility regulation at the state or federal level.

PUHCA 2005: The Public Utility Holding Company Act of 2005.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Retail Native Load Customers: The captive retail Customers for which Duke Power has an obligation under North Carolina law to engage in long-term planning and to supply all Electric Services, including installing or contracting for capacity, if needed, to reliably meet their electricity needs.

Retained Earnings: The retained earnings currently required to be listed on page 112, line 11, of the pre-Merger Duke Energy Corporation FERC Form 1.

Shared Services: The services that meet the requirements of these Regulatory Conditions and that the Commission has explicitly authorized Duke Power to take from Duke Energy Shared Services pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions, including, but not limited to, Regulatory Condition No. 20.

Utility Affiliates: The public utility operations of any Affiliate of Duke Power, including the public utility operations of PSI Energy, Inc., the public utility operations of Union Light, Heat and Power Company, and the transmission and distribution operations of The Cincinnati Gas and Electric Company.

B. PROTECTION FROM PREEMPTION

1. With respect to transactions between Duke Power and its Affiliates and to Affiliate Contracts, the following requirements and procedures shall apply:

   (a) Duke Power shall not engage in any such transactions without first filing the proposed Affiliate Contract with the Commission that memorializes any such dealings and taking such actions and obtaining from the Commission such decisions as are required under North Carolina law. Duke Power shall submit each proposed Affiliate Contract to the Public Staff for informal review at least ten days before filing it with the Commission. No additional advance notice is required for agreements that Duke Power intends to file pursuant to G.S. 62-153 unless the agreements are to be filed with the FERC, in which case subsection (c) applies.

   (b) All Affiliate Contracts to which Duke Power is a party shall provide the following:

(i) Duke Power's participation in the agreement is voluntary, Duke Power is not obligated to take or provide services or make any purchases or sales pursuant the agreement, and Duke Power may elect to discontinue its participation in the agreement at its election after giving any required notice;

(ii) Duke Power may not make or incur a charge under the agreement except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder;

(iii) Duke Power may not seek to reflect in rates any (A) costs incurred under the agreement exceeding the amount allowed by the Commission or (B) revenue level earned under the agreement less than the amount imputed by the Commission; and

(iv) Duke Power will not assert in any forum that the Commission's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is preempted and will bear the full risk of any preemptive effects of federal law with respect to the agreement.

(c) The following shall apply to all proposed Affiliate Contracts and any proposed amendments to existing Affiliate Contracts to which Duke Power is a party or which involve costs that will be assigned or allocated to Duke Power that are required or intended to be filed with the FERC:

(i) In order to enable the Commission to determine if it has jurisdiction over the proposed Affiliate Contract or amendment and how it will exercise its jurisdiction, Duke Power shall file a notice and a copy of the proposed Affiliate Contract or amendment with the Commission 30 days prior to a filing covered by this condition being made with the FERC. A copy shall be provided to the Public Staff at the time of the filing.

(ii) If an objection to Duke Power proceeding with the filing with the FERC is filed pursuant to the procedures set out in Regulatory Condition No. 59(b), the proposed filing shall not be made with the FERC until the Commission issues an order resolving the objection.

(iii) Filings of advance notices and copies of Affiliate Contracts and amendments to existing Affiliate Contracts pursuant to this subsection shall be in addition to filings required by G.S. 62-153, and the burden of proof as to those filings shall be as provided by statute.

(d) Duke Power shall certify that neither Duke Power, Duke Energy Corporation, any Affiliate, nor any Nonpublic Utility Operation has made any filing with the FERC or any other federal regulatory agency inconsistent with the foregoing. Such certification shall be repeated annually on the anniversary of the first certification.

2. With respect to any financing transaction involving Duke Power, Duke Energy Corporation or any of its Affiliates, the following shall apply:

(a) With respect to any financing transaction between Duke Power and Duke Energy Corporation or any one or more of its other Affiliates, any contract memorializing such transaction shall provide that Duke Power may not enter into any such financing transaction except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder; and

(b) With respect to any financing transaction (i) between and among any of the Affiliates if such contracts are reasonably likely to have an Effect on Duke Power's Rates or Service, or (ii) between Duke Power and any Affiliate, any contract memorializing such transaction shall provide that Duke Power may not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission.

3. At the time the Merger is closed, Duke Power shall own and control all assets or portions thereof used for the generation, transmission, and distribution of electric power to its North Carolina retail customers (with the exception of assets used to provide power purchased by Duke Power at wholesale). With respect to the transfer by Duke Power to any entity, affiliated or not, of the control of, operational responsibility for, or ownership of such assets with a gross book value in excess of ten million dollars ($10 million), the following shall apply:

(a) Duke Power shall provide notice with the Commission pursuant to Regulatory Condition No. 59(b) at least 30 days in advance of the proposed transfer;

(b) Any contract memorializing such a transfer shall provide the following:
  (i) Duke Power may not commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations and orders of the Commission promulgated thereunder; and
  (ii) Duke Power may not include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the Commission in accordance with North Carolina law; and

(c) Any filing with the FERC in connection with any transfer of control, operational responsibility or ownership that involves or otherwise affects Duke Power shall include the commitments in (b)(i) and (ii), above, and shall request that the FERC include language in its approval order(s) to the effect that its approval of the application in no way affects the right of the North Carolina Commission to review and determine the value of such asset transfer and establishing the value of the asset transfer for purposes of determining the rates for services rendered to Duke Power's North Carolina retail customers.

4. Subject to additional restrictions set forth in the Code of Conduct approved by this Commission, Duke Power shall not purchase electricity (or related ancillary services) from Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation under circumstances where the total all-in costs, including, but not limited to, generation, transmission, ancillary costs, distribution, and delivery point costs, incurred (whether directly or through allocation) exceed fair Market Value for comparable service, nor shall it sell electricity (or related ancillary services) to Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation for less than fair Market Value; provided, however, that such restrictions shall not apply to emergency transactions.

5. Duke Power shall retain the obligation to pursue least cost integrated resource planning for its Retail Native Load Customers and remain responsible for its own resource adequacy subject to Commission oversight in accordance with North Carolina law. Duke Power shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to its Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources specifically to Duke Power's Retail Native Load Customers.

6. The planning and dispatch of Duke Power system generation and purchased power resources subsequent to the Merger shall ensure that Duke Power's Retail Native Load Customers receive the benefits of those resources, including priority of service, to meet their electricity needs. Duke Power shall continue to serve its Retail Native Load Customers in North Carolina with the lowest-cost power it can reasonably generate or purchase from other sources before making power available for sales to customers that are not Retail Native Load Customers.

7. The following provisions shall apply to Duke Power's participation in the wholesale market subsequent to the issuance of the Commission's Order in Docket No. E-7, Sub 795:

   (a) To the extent that Duke Power proposes to enter into wholesale power contracts that grant native load priority to the following historically served customers: Schedule 10A Customers, Town of Highlands, WCU, the electric membership cooperatives (EMCs) within Duke's control area, North Carolina Municipal Power Agency No. 1, Piedmont Municipal Power Agency, and Saluda River Electric Cooperative, Inc., Duke Power is not required to file an advance notice with the Commission or receive its approval. Subject to the conditions set out in subsection (d) below, the retail native loads of these historically served wholesale customers shall be considered Duke Power's Retail Native Load Customers for purposes of Regulatory Condition Nos. 5 and 6; provided, however, that this subsection applies only to the same types of supplemental load and backstand requirements services that were historically provided to the Catawba Joint Owners under the Catawba Interconnection Agreements between Duke Power and the Catawba Joint Owners prior to 2001, which, for the North Carolina Electric Membership Corporation, only includes the EMCs within Duke Power's control area.

   (b) Before granting native load priority to a wholesale customer other than as provided for in subsection (a) above or to other companies' retail customers, Duke Power must provide 30 days' advance notice of its intent to grant native load priority and to treat the retail native load of a proposed wholesale customer as if it were Duke Power's retail native load pursuant to Regulatory Condition Nos. 5 and 6. The advance notice provisions of Regulatory Condition No. 59(b) apply.

   (c) To the extent that Duke Power's proposed wholesale power contracts or other sales of energy and capacity are at less than native load priority, then no advance notice is required and no approval by the Commission is needed. For purposes of this condition, "native load priority" is defined as power supply service being provided or electricity otherwise being sold with a priority of service equivalent to that planned for and provided by Duke Power to its Retail Native Load Customers.

(d) The following conditions apply to all wholesale contracts (including master and service agreements under Duke Power's market-based rate tariff) that are entered into by Duke Power, as seller, subsequent to the date of the Commission's order approving the Merger in this docket:

(i) The Commission retains the right to assign, allocate, and make pro-forma adjustments with respect to the revenues and costs associated with Duke Power's wholesale contracts for both retail ratemaking and regulatory accounting and reporting purposes.

(ii) Entry into wholesale contracts that grant native load priority or otherwise obligate Duke Power to construct generating facilities or make commitments to purchase capacity and energy to meet those contractual commitments constitutes acceptance by Duke Power, Duke Energy Corporation, and any Affiliates or Nonpublic Utility Operations thereof of the risks that investments in generating facilities or commitments to purchase capacity and energy to meet such contractual commitments and maintain an adequate reserve margin throughout the term of such contracts may become uneconomic sunk costs that are not recoverable from Duke Power's retail ratepayers. In a future Commission retail proceeding in which cost recovery is at issue, Duke Power shall (1) not claim that it does not bear this risk, and (2) acknowledge that the Commission retains full authority under Chapter 62 to disallow such costs as not used and useful and to allocate or assign such costs away from retail customers. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by Duke Power to meet the expected peak load of Duke Power's Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission.

(iii) Duke Power shall not assert before the FERC or any federal or state court that (1) transactions entered into pursuant to Duke Power's cost- or market-based rate authority or (2) the filing with, or acceptance for filing by, the FERC of any wholesale power contract imply a cost allocation methodology that is binding on the Commission, require the pass-through of any costs or revenues under the filed rate doctrine, or preempt the Commission's authority to assign, allocate, make pro-forma adjustments to, or disallow the revenues and costs associated with, Duke Power's wholesale contracts for both retail ratemaking and regulatory accounting and reporting purposes.

(iv) Duke Power shall not assert before any federal or state court that the exercise of authority by the Commission to assign, allocate, make pro forma adjustments to, or disallow the costs and revenues associated with Duke Power's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes in itself constitutes an undue burden on interstate commerce or otherwise violates the Commerce Clause of the United States Constitution. However, Duke Power retains the right to argue that a specific exercise of authority by the Commission violates the Commerce Clause based upon specific evidence of undue interference with interstate commerce.

(v) Except as provided in the foregoing conditions, Duke Power retains the right to challenge the lawfulness of any Commission order issued in connection with the assignment, allocation, pro-forma adjustments to, or disallowances of the revenues and costs associated with Duke Power's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes on any other grounds, including but not limited to the right outlined in G.S. 62-94(b).

8. Neither Duke Power, Duke Energy Corporation, another Affiliate, nor a Nonpublic Utility Operation shall assert that approval by the FERC of market-based rates, transfers of generating facilities, or any matter that involves Affiliates in any way preempts the Commission's authority to determine the reasonableness or prudence of Duke Power's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy.

9. No agreement shall be entered into, nor shall any filing be made with the FERC, by or on behalf of Duke Power, that (a) commits Duke Power to, or involves it in, joint planning, coordination, or operation of generation, transmission, or distribution facilities with one or more Affiliates, or (b) otherwise alters Duke Power's obligations with respect to these Regulatory Conditions, absent explicit approval of the Commission.

10. Duke Power, Duke Energy Corporation, the other Affiliates, and the Nonpublic Utility Operations shall file notice with the Commission 30 days prior to filing with the FERC any agreement, tariff, or other document or any proposed amendments, modifications, or supplements to any such document having the potential to (a) affect Duke Power's cost of service for its pre-merger system power supply resources or transmission system; (b) be interpreted as involving Duke Power in joint planning, coordination or operation of generation or transmission facilities with one or more Affiliates; or (c) otherwise affect Duke Power's rates or service. The advance notice provisions of Regulatory Condition No. 59(b) apply; provided, however, that, to the extent the filing with the FERC is not to be made by Duke Power, the advance notice procedures shall be for the purpose of a Commission determination as to whether the filing is reasonably likely to have an Effect on Duke Power's Rates or Service.

11. Any contract or filing regarding Duke Power's membership in or withdrawal from an RTO or comparable entity must be contingent upon state regulatory approval.

12. If the FERC does not approve Section 3.2 of the OATT Attachment K and Section 4.5 in Duke Power's Independent Entity Agreement (IE Agreement) dated July 22, 2005, both of which were filed in FERC Docket No. ER05-1236-000 on July 22, 2005, or makes any change that would make the Independent Entity a FERC-jurisdictional entity or otherwise affect the Commission's jurisdiction over the transmission component of Duke Power's retail service or rates, then Duke shall withdraw the filing and exercise its right to terminate the IE Agreement, absent an order from the Commission explicitly relieving Duke Power of this obligation.

13. Neither Duke Power, Duke Energy Corporation, another Affiliate, nor a Nonpublic Utility Operation shall assert in any forum, with respect to any contract or transaction in which Duke Power is involved or any contract or transaction involving Duke Energy Corporation, any other Affiliate, or any Nonpublic Utility Operation that may have an Effect on Duke Power's Rates or Service, that the Commission is in any way preempted from exercising any authority it has under North Carolina law as to:

(a) reviewing the reasonableness of any Affiliate commitment entered into by Duke Power, or from disallowing the costs of, or imputing revenues related to such commitment to, Duke Power;

(b) exercising its authority over financings or from setting rates based on the capital structure, corporate structure, debt costs, or equity costs that it finds to be appropriate for ratemaking purposes;

(c) reviewing the reasonableness of any commitment entered into by Duke Power to transfer an asset, mandating, approving or otherwise regulating a transfer of assets, or scrutinizing and establishing the value of the asset transfers for purposes of determining the rates for services rendered to Duke Power's retail customers; or

(d) otherwise exercising any lawful authority it may have.

Should any other entity so assert, neither Duke Power, Duke Energy Corporation, the other Affiliates, nor the Nonpublic Utility Operations shall support any such assertion and shall, upon learning of such assertion, so advise and consult with the Commission and the Public Staff regarding such assertion.

14. Duke Power, Duke Energy Corporation, the other Affiliates, and the Nonpublic Utility Operations shall (a) bear the full risk of any preemptive effects of federal law with respect to any contract, transaction, or commitment entered into or made by Duke Power or which may otherwise affect Duke Power's operations, service, or rates and (b) shall take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases or any other effects of such preemption. Such actions include, but are not limited to, filing with and making reasonable efforts to obtain approval from the FERC or other applicable federal entity of such commitments as the Commission deems reasonably necessary to prevent such preemptive effects.

15. The following provisions shall apply:

(a) Whenever the FERC issues rules regarding PUHCA 2005 or other rules reasonably likely to affect these Regulatory Conditions, Duke Power shall meet promptly with the Public Staff and negotiate in good faith whether and how these Regulatory Conditions might be or have been affected by such rules, and whether changes are necessary to maintain their intended protections. In the event the Public Staff and Duke Power are unable to reach agreement within a reasonable time after the issuance of final rules, the unresolved issues shall be submitted to the Commission for resolution. Any proposed changes to these Regulatory Conditions must be approved by the Commission.

(b) If PUHCA 2005 is amended, revised, or replaced by future legislation, Duke Power shall meet with the Public Staff promptly after the passage of such legislation and negotiate in good faith whether and how these conditions have been affected by such legislation, and whether changes are necessary to maintain their intended protections. In the event the Public Staff and Duke Power are unable to reach agreement within a reasonable time after passage of such legislation, the unresolved issues shall be submitted to the Commission for resolution. Any proposed changes to these Regulatory Conditions must be approved by the Commission.

16. Upon a decision by FERC on the petition for rehearing pending in Docket No. EC05-103-000, Duke Power shall meet promptly with the Public Staff and negotiate in good faith whether and how these Regulatory Conditions might be or have been affected by such order, and whether changes are necessary to maintain their intended protections. In the event the parties are unable to reach agreement within a reasonable time, the unresolved issues shall be submitted to the Commission for resolution.

17. In addition to the filing requirements of Commission Rule R8-27 and all other applicable statutes and Commission Rules, Duke Power shall, on a quarterly basis, file with the Commission the following: (a) a list of all applications, reports, contracts, rate schedules, and other documents (including the docket number(s) and a summary of each item listed) filed with or submitted to the FERC or other federal regulatory agency (or their staffs) by Duke Power, Duke Energy Corporation, Duke Energy Shared Services, other Affiliates, or the Nonpublic Utility Operations, to the extent such filings and submissions are reasonably likely to have a significant Effect on Duke Power's rates or service to its North Carolina retail customers, and (b) a list of all orders issued by FERC or any other federal regulatory agency (including docket number(s) and a summary of each order listed) in dockets to which Duke Power, Duke Energy Corporation, any other Affiliate, or any Nonpublic Utility Operation is a party, to the extent such orders are reasonably likely to have a significant Effect on Duke Power's rates or service to its North Carolina retail customers.

C. COST ALLOCATIONS AND RATEMAKING

18. Subject to additional provisions set forth in the Code of Conduct approved by this Commission, Duke Power shall take the following actions in connection with procuring goods and services for its utility operations from Affiliates or Nonpublic Utility Operations and providing goods and services to its Affiliates or Nonpublic Utility Operations:

    (a) Duke Power shall not seek to recover from its retail customers any costs that exceed fair Market Value for any service provided to Duke Power from Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation.

    (b) Duke Power shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that all goods and services procured from its Affiliates or Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-Affiliate sources or that Duke Power could not have provided the services or goods itself on the same basis at a lower cost. To this end, Duke Power must conduct periodic market price studies for goods and services it receives from Duke Energy Corporation, Duke Energy Shared Services, another Affiliate, or a Nonpublic Utility Operation.

(c) Duke Power shall have the burden of proving that all goods and services provided to Duke Energy Shared Services, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, Duke Power shall conduct periodic market price studies for goods and services provided to Duke Energy Corporation, Duke Energy Shared Services, another Affiliate, or a Nonpublic Utility Operation.

(d) The evaluation of providers of goods and services and the comparison of goods and services to Market Value required by the Regulatory Condition may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to Duke Power or by Duke Power are not commercially available, this Regulatory Condition shall not apply.

19. For the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and hearing or other appropriate opportunity for Duke Power to be heard, issue future orders relating to Duke Power's cost of service as the Commission may determine is necessary to ensure that Duke Power's operations and transactions with its Affiliates and Nonpublic Utility Operations are consistent with the Regulatory Conditions and Code of Conduct approved by the Commission, and with any other applicable decision of the Commission.

20. With regard to goods and services provided by Duke Power to Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations, and to goods and services, including Shared Services, provided to Duke Power by Duke Energy Shared Services, Duke Energy Corporation (should Duke Energy Corporation be allowed to provide any such goods or services), any other Affiliate, or any Nonpublic Utility Operation, the following conditions shall apply:

(a) No later than 60 days prior to the expected close of the Merger, Duke Power shall file pursuant to G.S. 62-153 final forms of service agreements that authorize the provision and receipt of non-power goods or services between and among Duke Power, its Affiliates or Nonpublic Utility Operations, the list(s) of goods and services it intends to take from Duke Energy Shared Services, and the basis for the determination of such list(s) and election of such services. All such lists that involve payment of fees or other compensation by Duke Power shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) No later than 30 days after such filing, the Public Staff shall file its response to Duke Power's filing, which shall include a recommendation as to how the Commission should proceed. If no Commission order is issued by the close of the Merger, Duke Power may operate on an interim basis, subject to ongoing Commission review, pursuant to the agreements as filed and make payments, subject to refund, as provided for therein.

(c) The services rendered by Duke Power to its Affiliates and Nonpublic Utility Operations and the services received by Duke Power from its Affiliates and Nonpublic Utility Operations pursuant to these agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as Duke Power's compliance with its Commission approved-Code of Conduct and all Regulatory Conditions placed upon it by the Commission, shall remain subject to ongoing review. These agreements shall be subject to any Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(d) No later than one month after the closing date of the Merger, Duke Power shall file with the Commission all newly-created cost allocation manuals (CAMs) and revisions to existing CAMs, including CAMs related to Shared Services provided by Duke Energy Shared Services. The CAMs referred to herein are those intended to govern the assignment and allocation of direct, indirect, and other costs associated with goods and services (i) provided by Duke Power to Duke Energy Corporation, Duke Energy Shared Services, other Affiliates, and the Nonpublic Utility Operations, or (ii) by those entities to Duke Power and to each other (to the extent they may affect Duke Power's cost of service to its North Carolina retail electric Customers) and shall include a full description thereof, including a detailed review of common costs to be allocated and allocation factors to be used. The following additional provisions shall apply:
(i) The CAM(s) shall be updated annually, and the revised CAM(s) shall be filed with the Commission no later than March 31 of the year that the CAM(s) are to be in effect. Duke Power shall review allocation factors every two years, and the result of such review shall be filed with the Commission; and
(ii) Interim changes shall be made to the CAM(s), if and when necessary, and shall be filed with the Commission. No changes shall be made to the cost allocations, cost allocation methodologies, or related accounting entries associated with goods and services (including Shared Services provided by Duke Energy Shared Services) provided to or by Duke Energy Corporation, other Affiliates, and the Nonpublic Utility Operations until Duke Power has given 15 days notice to the Commission of the proposed changes.

(e) No later than 30 days after the closing date of the Merger, Duke Power shall file with the Commission pursuant to G.S. 62-153 the list(s) of goods and services (1) it intends to offer to Duke Energy Corporation, Duke Energy Shared Services, other Affiliates, and the Nonpublic Utility Operations, and (2) it intends to take from Duke Energy Corporation, other Affiliates, and the Nonpublic Utility Operations (excluding Shared Services provided by Duke Energy Shared Services, which are required to be filed pursuant to subsection (a) above), and the basis for the determination of such list(s) and election of such services. All such lists that involve payment of fees or other compensation by Duke Power shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission. The following additional provisions shall apply:
(i) The list(s) of goods and services, including the list required by subsection (a) above, shall be updated annually, and the revised list(s) shall be filed with the Commission no later than March 31 of the year that they are to be in effect; and

(ii) Interim changes shall be made to the list(s) of goods and services, if and when necessary, and shall be filed with the Commission. No changes shall be made to the list(s) of goods and services until Duke Power has given 15 days notice to the Commission of the proposed changes.

(f) With respect to interim changes to the CAM(s) or the list(s) of goods and services, for which 15 days notice to the Commission is required, the following procedures shall apply: Before the end of the notice period, the Public Staff shall file a response and make a recommendation as to how the Commission should proceed. If the Commission has not issued an order within 30 days of the end of the notice period, Duke Power may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter.

(g) The advance notice provisions of Regulatory Condition No. 59(b) do not apply to any of the filings made pursuant to this condition.

(h) The Service Agreements, the CAM(s) and the assignments and allocations of costs pursuant thereto, the biannual allocation factor reviews, the list(s) and the goods and services provided pursuant thereto, and the changes to these documents shall be subject to ongoing Commission review, and Commission action if appropriate.

21. Notwithstanding any of the provisions contained in these Regulatory Conditions, to the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of Duke Power result in significant trapped costs related to "non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding company system," including Duke Power, Duke Power may, after the effective date of the Energy Policy Act of 2005 (PUHCA 2005), request pursuant to Section 1275(b) of Subtitle F in Title XII of PUHCA 2005 that the FERC "review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company." Such review and authorization shall have whatever effect it is determined to have under the law. The quoted language in this condition is taken directly from Section 1275(b) of Subtitle F in Title XII of PUHCA 2005. The terms "associate company" and "holding company system" are defined in Sections 1262(2) and 1262(9), respectively, of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

22. Transactions between Duke Power and Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations, and other transactions among Affiliates if such transactions are reasonably likely to have a significant Effect on Duke Power's Rates or Service, shall be reviewed at least annually by Duke Energy Corporation's internal auditors. To the extent external audits of the transactions are conducted, Duke Power shall make available such audits for review by the Public Staff and the Commission. Duke Power shall make available for review by the Public Staff and the Commission all workpapers relating to internal audits and all other internal audit workpapers, if any, related to affiliate transactions, and shall not oppose Public Staff and Commission requests to review relevant external audit workpapers.

23. For North Carolina retail electric cost of service/ratemaking purposes, Duke Power electric system costs shall be assigned or allocated among retail and wholesale jurisdictions based on reasonable and appropriate cost causation principles. Assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected by the manner and amount of recovery of electric system costs from the Catawba Joint Owners as a result of agreements between Duke Power and the Catawba Joint Owners. For cost of service/ratemaking purposes, North Carolina retail ratepayers will be held harmless from any cost assignment or allocation of costs resulting from the agreements between Duke Power and the Catawba Joint Owners.

24. Neither Duke Power, Duke Energy Corporation, any other Affiliate, nor a Nonpublic Utility Operation shall assert that any interested party is prohibited from seeking the inclusion in future rate proceedings of cost savings that may be realized as a result of the Merger.

25. Direct expenses associated with costs to achieve the Merger shall be excluded from retail cost of service for ratemaking purposes. Duke Power shall bear the burden of proof to demonstrate in its first rate case after closing of the Merger that any capital costs, such as system integration costs, associated with costs to achieve the merger that Duke seeks to recover from the North Carolina retail customers are to the benefit of North Carolina retail customers. The North Carolina portion of costs to achieve merger savings shall be reflected in Duke Power's North Carolina ES-1 report as recorded on its books and records under generally accepted accounting principles. To the extent a one-year rate decrement is approved, the rate decrement's impact may be spread evenly over five years in the ES-1 report, commencing with the date the rate decrement is implemented. However, Duke Power shall include as a footnote in the ES-1 report the merger related costs to achieve that were expensed during the relevant period. If the merger is not consummated, neither the cost of any termination payment nor the receipt of a termination payment between Duke Energy and Cinergy shall be allocated to Duke Power's books. Nor shall Duke Power's North Carolina retail customers otherwise bear any direct expenses or costs associated with a failed merger.

26. The revenues from certain Duke Power electric utility wholesale transactions are (a) assigned or allocated in part to Duke Power's North Carolina retail operations and (b) treated in part as a credit to jurisdictional fuel expenses in Duke Power's annual North Carolina retail fuel proceedings. To the extent commitments to Duke Power's wholesale customers relating to the Merger are made by or imposed upon Duke Power, the effects of which serve to (a) decrease the net bulk power revenues ordered to be shared by the Commission in Docket No. E-7, Sub 751, (b) increase the North Carolina retail cost of service, or (c) increase North Carolina retail fuel costs under reasonable cost assignment and allocation practices approved or allowed by the Commission, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes.

27. To the extent that other such commitments are made by or imposed upon Duke Power, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation relating to the Merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or North Carolina retail fuel costs under reasonable cost allocation practices, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

28. Any acquisition adjustment that results from the Merger shall be excluded from Duke Power's utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes so that it does not affect Duke Power's North Carolina retail electric rates and charges.

29. Duke Power, Duke Energy Corporation, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina retail ratepayers harmless from effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting North Carolina retail customers.

30. Duke Power's North Carolina retail customers shall be held harmless from all current and prospective liabilities of Cinergy Corp. and its subsidiaries including, but not limited to, the litigation involving manufactured gas plant sites, asbestos claims, environmental compliance, pensions and other employee benefits, and taxes.

31. Duke Power shall file an annual report of affiliated transactions with the Commission in the format prescribed by the Commission in Docket No. E-7, Sub 694. The report shall be filed on or before May 30 of each year, for activity through December 31 of the preceding year. Changes may be made, if and when deemed necessary, to the required affiliated transaction reporting requirements and submitted to the Commission for approval.

32. Periodic comprehensive third-party independent audits of the affiliate transactions undertaken pursuant to the affiliate agreements filed in this docket (as subsequently re-filed in accordance with Regulatory Condition No. 20 and allowed to go into effect by the Commission) shall be conducted no less often than every two years. The independent auditor shall have sufficient access to the books and records of Duke Power, Duke Energy Corporation, other Affiliates, and all of the Nonpublic Utility Operations to perform the audits. The scope of the audits shall include Duke Energy Corporation's and Duke Power's compliance with all conditions ordered herein concerning affiliate company transactions, including the propriety of the transfer pricing of goods and services between and/or among Duke Power and its affiliates, that is, Duke Energy Corporation, other Affiliates, and all of the Nonpublic Utility Operations. Duke Power and the Public Staff shall confer and jointly identify one or more proposed independent auditors. Other parties shall have an opportunity to comment and propose additional auditors. Selection of the independent auditor shall be made by the Commission. The independent auditor shall be supervised in its duties by the Public Staff. Not later than 60 days after consummation of the Merger, the Public Staff shall file a recommendation with the Commission as to how and when the first independent audit should be commenced. Duke Energy Corporation shall bear the cost of the audits, and all such costs shall be excluded from Duke Power's utility accounts, except to the extent that reasonable assignments or allocations of such audit costs may be included in the transfer prices charged to Duke Power for goods and services provided to it by Duke Energy Corporation, other Affiliates, and all of the Nonpublic Utility Operations; provided however, that such transfer prices, individually, shall not exceed prices determined in strict compliance with all other Regulatory Conditions and the Code of Conduct as prescribed herein. The appropriateness of the assignment or allocation of the cost of the audits to utility accounts in the manner described above, if any, shall be subject to review in subsequent ratemaking proceedings. The auditor's reports shall be filed with the Commission. Duke Power may request a change in the frequency of the audit reports in future years, subject to approval by the Commission. Duke Energy Corporation shall endeavor to

coordinate the various state affiliate transaction audits. To the extent separate third-party independent audits continue to be performed in the other states, Duke Power shall provide the reports of those audits to the Public Staff and the Commission.

32a. Duke Power shall track its actual net merger savings for the five-year period beginning immediately subsequent to consummation of the Merger and submit quarterly reports delineating the actual net benefits derived therefrom with respect to its North Carolina retail operations. Said reports shall include explanations of the methodologies, assumptions, judgments, and estimates, if any, on which the reports are based. Copies of the workpapers setting forth the calculations of the net merger savings shall also be provided. These reports shall be verified by either the Chief Executive Officer, a senior-level financial officer, or the responsible accounting officer of Duke Power and shall be provided in conjunction with Duke Power's quarterly NCUC ES-1 Reports. The Public Staff is hereby requested to investigate, verify, and assess the reports required in this regard and submit an annual report to the Commission setting forth its findings and recommendations. It is further requested that the Public Staff's annual report be submitted on or before June 1st with respect to Duke Power's quarterly reports for the preceding calendar year.

33. Within six months after the closing date of the Merger, Duke Power shall file with the Commission revisions to its electric cost of service manual to reflect any changes to the cost of service determination process made necessary by the Merger, any subsequent alterations in the organizational structure of Duke Power, Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations, or other circumstances that necessitate such changes.

D. <u>CODE OF CONDUCT</u>

34. Duke Power, Duke Energy Corporation, the other Affiliates, and the Nonpublic Utility Operations shall be bound by the Code of Conduct approved by the Commission in Docket No. E-7, Sub 795, and as it may subsequently be amended.

E. <u>FINANCE/CORPORATE GOVERNANCE</u>

35. Duke Energy Corporation shall maintain its books and records so that any net equity investment in Cinergy Corp. or its subsidiaries (or their successors) by Duke Energy Corporation or any of its Affiliates can be identified and made available on an ongoing basis. This information shall be provided to the Public Staff upon its request.

36. Duke Energy Corporation and Duke Power shall keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. This information shall be provided to the Public Staff upon its request.

37. Duke Power shall keep its books and records so that the amount of Duke Energy Corporation's equity investment and member's equity in Duke Power can be identified and made available upon request on an ongoing basis. This information shall be provided to the Public Staff upon request.

37a. Effective upon consummation of the merger and beginning with the quarterly report due for the first 12-month reporting period beginning concurrent therewith or subsequent thereto, whichever shall first occur, Duke Power shall begin transitioning to its actual capital structure for purposes of calculating and reporting its quarterly North Carolina retail jurisdictional earnings in its NCUC ES-1 Reports to the Commission. Said transition shall be accomplished by use of a consistent, uniform, systematic approach applied on a quarterly basis such that exclusive use of the Company's actual capital structure will be fully phased in and reflected in the Company's NCUC ES-1 Report for the 12-month period ending June 30, 2007.[1] Once fully phased in, the information to be submitted as part and parcel of, or in conjunction with, the NCUC ES-1 Reports shall include, among other things, a calculation of the 13-month average actual capital structure utilized in such reports, with the individual capital components (long-term debt, member's and/or common equity, etc.) on a total-company basis shown separately and in total. NCUC ES-1 Reports filed by Duke Power during the phase-in shall clearly disclose and reflect the methodology employed by Duke Power in calculating the 13-month average capital structure utilized therein. In recognition of the change in its organizational structure that will result upon consummation of the merger, Duke Power shall, following the merger, continue to provide to the Commission and/or the Public Staff all financial and operational information which is currently being provided on an ongoing basis by Duke Energy Corporation. Duke Power shall base such reports primarily on the corporate entity Duke Power.

As part of its NCUC ES-1 Reports, Duke Power shall also include a schedule of any capital contribution(s) received from Duke Energy Corporation in the applicable calendar quarter. The same requirements set forth above shall also apply to NCUC ES-1 Quarterly reports filed for Nantahala Power & Light Company subsequent to consummation of the merger.

38. To the extent the cost rates of any of Duke Power's long-term debt (more than one year) or short-term debt (one year or less) are or have been adversely affected, through a ratings downgrade or otherwise, by the Merger, a replacement cost rate to remove the effect shall be used for all purposes affecting any of Duke Power's retail rates and charges. This replacement cost rate shall be applicable to all financings, refundings, and refinancings taking place following the change in ratings. This procedure shall be effective through Duke Power's next general rate case. As part of Duke Power's next general rate case, any future procedure relating to a replacement cost calculation will be determined. This condition does not indicate a preference for a specific debt rating for Duke Power within the intended investment grade range provided for in Regulatory Condition No. 43 on current or prospective bases.

39. Within 90 days from the date of redemption of current Duke Energy Corporation's preferred stock, announced via a press release dated November 14, 2005, Duke Energy Corporation or Duke Power shall file a report with the Commission identifying the source(s) of funds used to execute the redemption and describing all costs, fees, etc., that are associated with the redemption.

40. Duke Power shall identify as clearly as possible long-term debt (of more than one year's duration) that it issues in connection with its regulated utility operations and capital requirements or to replace existing debt.

[1] This phase-in requirement is not, and should not be construed to be, a precedent or otherwise determinative with respect to the capital structure appropriate for use in determining the test-year cost of service for purposes of setting rates prospectively in the context of any future general rate case proceeding for Duke Power.

41. With respect to all proposed financing transactions, the following shall apply:

(a) For all types of financings for which Duke Power (or its subsidiaries, if any) are the issuers of the respective securities, Duke Power (or its subsidiaries, if any) shall request approval from the Commission to the extent required by G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16. Generally, the format of these filings should be consistent with past practices. A "shelf registration" approach (similar to Docket No. E-7, Sub 727) may be requested.

(b) For all types of financings by Duke Energy Corporation, other than short-term debt as described in G.S. 62-167, the following shall apply:

(i) On or before January 15 of each year, Duke Energy Corporation shall file with the Commission and serve on the Public Staff an advance confidential plan of all securities issuances that are anticipated to occur during that calendar year. For 2006, an advance confidential plan shall be filed as soon as possible after the merger is consummated. The annual confidential plan shall include a description of all financings that Duke Energy Corporation reasonably believes may occur during the applicable calendar year. A description for each financing shall include the best estimates of the following: type of security; estimate of cost rate (e.g., interest rate for debt); amount of proceeds; brief description of the purpose/reason for issue; and amount of proceeds, if any, that may flow to Duke Power.

(ii) If at any time material changes to the financing plans included in the filed plan appear likely, Duke Energy Corporation shall file a revised 30-day advance confidential plan that specifically addresses such changes with the Commission and serve such notice on the Public Staff.

(iii) At the time of the confidential plan filings identified above, Duke Energy Corporation shall also file a non-confidential notice that states that a confidential plan has been filed in compliance with Regulatory Condition No. 41.

(iv) Duke Energy Corporation may proceed with equity issuances upon the filing of the confidential plan. However, actual debt issuances shall not occur until 30 days after the advance confidential plan or revised plans are filed. In the event it is not feasible for Duke Energy Corporation to file a revised advance confidential plan for a material change 30 days in advance, such plan shall be filed by a date that allows adequate time for review or a debt issuance shall be delayed to allow such review.

(v) Within 15 days after the filing of an advance confidential plan or revised plan, the Public Staff shall file a confidential report with the Commission with respect to whether any debt issuances require approval pursuant to G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16 and shall recommend that the Commission issue an order deciding how to proceed. Duke Energy Corporation shall have seven days in which to respond to the report. If the Commission determines that any debt issuance requires approval, the Commission shall issue an order requiring the filing of an application and no issuance shall occur until the Commission approves the application. If the Commission determines that no debt issuance requires approval, the Commission shall issue an order so ruling. At the end of the notice period, Duke Energy Corporation may proceed with the debt issuance, but shall be subject to any fully adjudicated Commission order on the matter; provided, however, that nothing herein shall affect the applicability of G.S. 62-170 or other similar provision to such securities or obligations.

(vi) On or before April 15 of each year, Duke Energy Corporation shall file with the Commission a report on all financings that were executed for the previous calendar year. The actual reports should include the same information as required above for the advance plans plus the actual issuance costs.

(c) If a filing with the Securities and Exchange Commission or other federal agency will be made in connection with a securities issuance, the notice shall describe such filing(s) and indicate the approximate date on which it would occur.

(d) All securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Condition No. 54.

(e) The advance notice provisions of Regulatory Condition No. 59(b) do not apply to any of the filings made pursuant to this condition.

42. These conditions do not supersede any orders or directives of the Commission regarding the issuance of specific securities by Duke Power or Duke Energy Corporation. The approval of the Merger by the Commission does not restrict the Commission's right to review, and by order to adjust, Duke Power's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the Merger.

43. Duke Power shall manage its business with the intention of maintaining an investment grade debt rating on all of its rated debt issuances with all of its debt rating agencies. If Duke Power's debt rating falls to the lowest level still considered investment grade at the time, Duke Power shall provide notice to the Commission and Public Staff within five (5) days of such change and an explanation as to why the downgrade occurred. Within 45 days of such notice, Duke Power shall meet with the Commission and the Public Staff and provide information regarding the steps it intends to take to maintain and improve its debt rating. The advance notice provisions of Regulatory Condition No. 59(b) do not apply to this Condition.

44. Duke Energy Corporation and Duke Power shall ensure that Duke Power has sufficient access to equity and debt capital to enable Duke Power to adequately fund and maintain its current and future generation, transmission, and distribution systems and otherwise meet the service needs of its customers at a reasonable cost.

45. Duke Power shall limit cumulative distributions paid to Duke Energy Corporation subsequent to the Merger to (i) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (ii) any future earnings recorded by Duke Power subsequent to the Merger.

46. Duke Power shall not invest in a non-regulated utility asset or any non-utility business venture exceeding $50 million dollars in purchase price or gross book value to Duke Power unless it provides 30 days' advance notice, to which the advance notice provisions of Regulatory Condition No. 59(b) shall apply. Purchases of assets, including land, that will be held with a

definite plan for future use in providing Electric Services in Duke Power's franchise area shall be excluded from this advance notice requirement.

47. By April 15 of each year, Duke Energy Corporation shall provide to the Commission and the Public Staff a report summarizing Duke Energy Corporation's investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) in relation to its level of consolidated retained earnings and consolidated total capitalization at the end of the preceding year. Exempt wholesale generator and foreign utility company are defined in Section 1262(6) of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

48. Duke Power shall borrow short-term funds in the financial markets or through the "Utility Money Pool Agreement" (Utility MPA), provided that the Utility MPA (a) is modified to exclude Tri-State Improvement Company; and (b) continues to provide that no loans through the Utility Money Pool will be made to, and no borrowings through the Utility Money Pool will be made by, Duke Energy Corporation and Cinergy Corporation. If, after December 31, 2008, certain of The Cincinnati Gas & Electric Company's generation assets are not dedicated to serving retail load in its service territory and are not subject to the rate stabilization plan (as approved in Case 03-93-ATA) or traditional regulation, then Duke Power shall obtain Commission approval to continue to participate in the Utility MPA. Duke Power shall acquire its long-term debt funds through the financial markets, and shall neither borrow from nor lend to, on a long-term basis, Duke Energy Corporation or any of its other Affiliates. To the extent that Duke Power borrows on short-term or long-term bases in the financial markets and it is feasible to obtain a debt rating, its debt shall be rated under its own name.

49. Duke Energy Corporation shall comply with New York Stock Exchange Listing Standards with respect to the composition of its Board of Directors.

50. Duke Energy Corporation shall notify the Commission subsequent to Board approval and as soon as practicable following any public announcement of any investment in a regulated or non-regulated business representing five (5) percent or more of Duke Energy Corporation's market capitalization. The advance notice provisions of Regulatory Condition No. 59(b) do not apply to this Condition.

51. If an Affiliate of Duke Power experiences a default on an obligation that is material to Duke Energy Corporation or files for bankruptcy, and such bankruptcy is material to Duke Energy Corporation, Duke Power shall notify the Commission in advance, if possible, or as soon as possible, but not later than ten days from such event. The advance notice provisions of Regulatory Condition No. 59(b) do not apply to this Condition.

52. By March 31 of the first calendar year following the close of the Merger and each March 31 thereafter, Duke Power shall file an annual report in the format provided hereinafter. Duke Power and the Public Staff shall meet and reach agreement as to the list of Affiliates for purposes of this Annual Report that constitute Significant Affiliates and Duke Power shall file this list with the Commission. In the event the Public Staff and Duke Power are unable to reach agreement within a reasonable time, both shall file their proposed lists and submit the unresolved issues to the Commission for resolution. Thereafter, the list shall be updated as appropriate on an annual basis.

ANNUAL REPORT ON CORPORATE
GOVERNANCE AND FINANCE

Report for Duke Power Company, LLC,
Year Ending December 31, ____ .

1. Provide a complete, detailed organizational chart that identifies Duke Power and each Significant Affiliate, including major groups and departments. State the business purpose of each company and each major group and each department within each company. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

2. Identify all Significant Affiliates that are considered to constitute non-regulated investments and provide each company's total capitalization, the percentage it represents of Duke Energy Corporation's total non-regulated investments, and the percentage it represents of Duke Energy Corporation's total investments. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

3. Provide an assessment of the risks that each unregulated Significant Affiliate could pose to Duke Power based upon current business activities of those affiliates and any contemplated significant changes to those activities.

4. Provide a description of Duke Power's and each Significant Affiliate's actual capital structure. In addition, describe Duke Energy Corporation's and Duke Power's goals for Duke Power's capital structure and plans for achieving such goals.

5. Provide a complete description of all protective measures (other than those provided for by the Regulatory Conditions adopted in Docket No. E-7, Sub 795) in effect between Duke Power and any of its Affiliates and a description of how each measure operates. This should include, but not be limited to, mitigation of Duke Power's exposure in the event of a bankruptcy proceeding involving any affiliate(s).

6. Provide a list of corporate officers and other key personnel that are shared between Duke Power and any Affiliate, along with a description of each person's position(s) with, and duties and responsibilities to each entity.

7. Provide a calculation of Duke Energy Corporation's total market capitalization as of December 31 of the preceding year for common equity, preferred stock, and debt.

53. The cost of capital conditions included herein shall also apply to Duke Power's determination of its maximum allowable AFUDC rate, the rate of return applied to any of Duke Power's deferral accounts and regulatory assets and liabilities that accrue a return, and any other component of Duke Power's cost of service impacted by the cost of debt.

53a. Duke Power shall carry forward to its post-merger balance sheet, among other things, the balances, without adjustment(s), in all accounts of the following nature: regulatory liability; deferred credit, including deferred income tax; reserve; valuation; and over-accrued liability accounts, if any, applicable and/or reasonably attributable to Duke Energy's regulated electric utility operations which existed prior to consummation of the merger. Further, Duke Energy shall promptly, where appropriate, distribute to Duke Power any and all payments, refunds, dividends, other distributions, etc., received by Duke Energy subsequent to the merger that have arisen from and/or are attributable to payments, distributions, etc., having been made by its regulated electric utility operations prior to the merger, including such funds received as a result of retrospective and/or other insurance plans.

F. <u>FUTURE PROPOSED MERGERS</u>

54. For all proposed mergers, acquisitions, or other business combinations involving Duke Energy Corporation, Duke Power, other Affiliates, or the Nonpublic Utility Operations, the following conditions shall apply:

   (a) For any proposed merger, acquisition, or other business combination by or affecting Duke Power, Duke Power shall file an application for approval pursuant to G.S. 62-111(a) at least 180 days before the proposed closing date for such merger, acquisition, or other business combination.

   (b) For any proposed merger, acquisition, or other business combination that is believed not to affect Duke Power but which involves Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations and which has a transaction value exceeding $1 billion:

      (i) Advance notification shall be filed with the Commission at least 90 days prior to the proposed closing date for such proposed merger, acquisition or other business combination. The advance notification is intended to provide the Commission an opportunity to determine whether the proposed merger, acquisition, or other business combination is reasonably likely to affect Duke Power so as to require approval pursuant to G.S. 62-111(a). The notification shall contain sufficient information to enable the Commission to make such a determination. If the Commission determines that such approval is required, the 180-day advance filing requirement in subsection (a), above, shall not apply.

      (ii) Any interested party may file comments within 45 days of the filing of the advance notification.

      (iii) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall recommend that the Commission issue an order deciding how to proceed. If the Commission determines that the merger, acquisition, or other business combination requires approval pursuant to G.S. 62-111(a), the Commission shall issue an order requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination. If the Commission determines that the merger, acquisition, or other business combination does not require approval pursuant to G.S. 62-111(a), the Commission shall issue an order so ruling. At the end of the notice period, if no order has been issued, Duke Energy Corporation, any other Affiliate, or the Nonpublic Utility Operation may proceed with the merger, acquisition, or other business combination but shall be subject to any fully-adjudicated Commission order on the matter.

(iv) The advance notice provisions of Regulatory Condition No. 59(b) do not apply to any of the filings made pursuant to this Condition.

G. STRUCTURE/ORGANIZATION

55. Duke Power shall file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, employees, rights, obligations, assets, or liabilities from Duke Power to Duke Energy Shared Services, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation that potentially would have a significant effect on Duke Power's public utility operations. The advance notice provisions of Regulatory Condition No. 59(b) apply to this Condition.

56. The benefits, costs, and associated risks of the Merger and the operation of Duke Power under a holding company structure shall continue to be subject to Commission review. To the extent the Commission has authority under North Carolina law, it may order lawful modifications to the structure or operations of Duke Energy Corporation, Duke Energy Shared Services, another Affiliate, or a Nonpublic Utility Operation, and to take whatever action the Commission deems necessary to protect Duke Power's North Carolina retail customers, including, but not limited to, modifications necessary to address changes in the electric industry.

57. Duke Power shall meet and consult with, and provide requested relevant data to, the Public Staff, at least semiannually through 2010, unless there is agreement between Duke Power and the Public Staff that no meeting is necessary, regarding plans for significant changes in Duke Power's or Duke Energy Corporation's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on Duke Power's retail rates, operations and service; and proposals for assuring that such plans do not adversely affect Duke Power's North Carolina retail electric customers. To the extent that proposed significant changes are planned for any Affiliate's or Nonpublic Utility Operation's organization, structure, or activities, then Duke Power's plans and proposals for assuring that those plans do not adversely affect its customers must be included in these meetings. Duke Power or the Public Staff may initiate meetings more frequently if significant events or other changes require. Duke Power shall inform the Public Staff promptly of any such events and changes.

58. Duke Power shall provide to the Public Staff, 30 days prior to finalization, the Tax Sharing Agreement, any plans to consolidate Duke Energy Corporation's and Cinergy Corp.'s employee benefit plans, and any other similar agreements and plans.

H. PROCEDURES

59. Except to the extent a condition, Commission order, rule, or statute specifically provides otherwise, the following procedures shall apply with respect to all filings made pursuant to these Regulatory Conditions:

(a) All filings pursuant to the Regulatory Conditions shall be made as follows:
  (i) Regulatory Condition filings that do not involve advance notices shall be made in Docket No. E-7, Sub 795A.
  (ii) Each filing for which the Regulatory Conditions require an advance notice shall be assigned a new, separate Sub docket. Such a filing shall state what condition and notice period are involved and whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary.

(b) The following additional procedures shall apply to all advance notices filed pursuant to Condition Nos. 1, 3, 7(b), 10, 46, and 55:

  (i) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.
  (ii) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.
  (iii) Duke Power shall serve such advance notices on each party to Docket No. E-7, Sub 795, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.
  (iv) To effectuate this Regulatory Condition, Duke Power shall serve pertinent information on all parties at the time it serves the advance notice. No later than 90 days after the closing date of the Merger, Duke shall have solicited input from the parties to Docket No. E-7, Sub 795, and shall have developed and circulated to those parties lists of pertinent information to be provided in each type of advance notice proceeding. Should Duke and any party not agree as to the adequacy of these lists, they shall take the matter to the Commission for resolution. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If Duke Power objects to a discovery request, Duke Power and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, Duke Power may file a motion for a protective order with the Commission.
  (v) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response within the notice period. Duke Power may file a reply to the response(s).
  (vi) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.
  (vii) If neither the Public Staff nor any other party files an objection to the activities, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(viii) If the Public Staff or any other party files a timely objection to the activities to be undertaken by Duke Power, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no order, whether procedural or substantive, has been issued, Duke Power, Duke Energy Corporation, any other Affiliate, or the Nonpublic Utility Operation may proceed with the activity to be undertaken, but shall be subject to any fully-adjudicated Commission order on the matter.

(ix) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(x) The precedential effect of advance notice proceedings, like most issues of *res judicata*, will be decided on a fact-specific basis.

(xi) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement.

(xii) Duke Power, the Public Staff, or any party may move for a waiver if exigent circumstances in a particular case justify such.

I. SERVICE QUALITY

60. Duke Power shall continue to take steps to implement and further its commitment to providing superior public utility service. To the extent the quality of service practices of Cinergy Corp. or its utility subsidiaries are found to be superior to Duke Power's, Duke Power shall make every reasonable effort to incorporate those practices into its own practices to the extent practicable. Duke Power shall work with the Public Staff (a) to continue to monitor and improve service quality, and (b) to ensure the service quality indices (e.g., SAIDI, SAIFI) are appropriate and to revise them if and when such revisions are necessary. Duke Power commits that for a period of five years following the Merger, that it shall advise the Commission at least annually on the adoption and implementation of best practices at Duke Power following the completion of the Merger between Cinergy and Duke Energy.

J. TAX

61. Under any tax sharing agreement, Duke Power shall not seek to recover from its North Carolina retail ratepayers any tax costs that exceed Duke Power's tax liability calculated as if it were a stand-alone, taxable entity for tax purposes.

62. The appropriate portion of any income tax benefits associated with Duke Energy Shared Services shall accrue to North Carolina retail operations for regulatory accounting, reporting, and ratemaking purposes.

K. NANTAHALA

63. Until otherwise ordered by the Commission, Nantahala's retail customers shall continue to receive the benefits of Nantahala's historic hydroelectric generating resources.

64. Until otherwise ordered by the Commission, Nantahala's retail customers shall continue to be charged rates based on Nantahala's own cost of service, separate from that relating to the non-Nantahala Duke Power service area, Nantahala's purchased power costs shall continue to be determined in accordance with the Duke-Nantahala Interconnection Agreement, and stand-alone Duke Power and Nantahala financial information shall continue to be provided as it has been prior to the Merger.

L. GENERAL

65. In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of Duke Power, Duke Energy Corporation, other Affiliates, and the Nonpublic Utility Operations.

66. Duke Energy Corporation shall make available in Charlotte, North Carolina, all Duke Power financial books and records.

67. All previously issued Commission orders applicable prior to the Merger to Duke Energy Corporation, to Duke Power as a division of Duke Energy Corporation, to Nantahala as an area or division of Duke Power, or to Nantahala Power and Light Company shall remain applicable to Duke Power after the Merger, unless superseded by Commission order. Within 30 days of the Commission's Order approving the Merger, Duke Energy shall file a list of the conditions imposed by the Commission in Docket Nos. E-7, Subs 557, 596, 694, and 700, as well as in other dockets, that have not been superceded by these Regulatory Conditions. The Public Staff and other parties shall have 30 days to file responses. The Commission will then determine which of the previously approved conditions remain in effect. The advance notice provisions of Regulatory Condition No. 59(b) do not apply to this Condition.

68. These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions either (a) constitute specific exercises of the Commission's authority, (b) provide mechanisms that enable the Commission to determine in advance the extent of its authority and jurisdiction over proposed activities of and transactions involving Duke Power, Duke Energy Corporation, other Affiliates or Nonpublic Utility Operations, or (c) protect the Commission's jurisdiction from federal preemption and its effects. Pursuant to these conditions, Duke Power, Duke Energy Corporation, and other Affiliates waive certain of their federal rights as specified in these Regulatory Conditions, but do not otherwise agree that the Commission has authority other than as provided for in Chapter 62. Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy Corporation, Duke Power, and its Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina law or the other grounds listed in G.S. 62-94(b).

69. These Regulatory Conditions are not intended to and do not purport to impose legal obligations on entities in which Duke Energy Corporation does not directly or indirectly have a controlling voting interest.

70. Duke Power, Duke Energy Corporation and its Affiliates may request a waiver of any aspect of these Regulatory Conditions if exigent circumstances in a particular case justify such by filing a request for waiver with the Commission for approval.

71. These Regulatory Conditions shall become effective only upon closing of the Merger.

72. These Regulatory Conditions are not intended to and do not purport to affect any rights of the parties to Docket No. E-7, Sub 795, with respect to participation in subsequent proceedings.

M. RATE REDUCTION, MOST FAVORED NATION CLAUSE, CONTRIBUTION TO ENERGY- AND ENVIRONMENTAL-RELATED PROGRAMS, AND RATE INVESTIGATION

73. Duke Power shall implement a one-year across-the-board decrement to rates for the benefit of its North Carolina retail customers in the amount of $117,517,000. In addition, any fuel-related savings associated with the Merger shall be flowed through to Duke Power's North Carolina retail customers pursuant to G.S. 62-133.2.

74. Following the approval of the Merger by the state commissions of Kentucky, Ohio, and South Carolina and approval of the affiliate agreements filed with the Indiana Utility Regulatory Commission in connection with the Merger, any sharing mechanisms pursuant to which Merger savings are shared with retail customers in each of these states will be reviewed to identify the utility whose electric retail customers will receive the largest percentage of the net merger savings to be achieved over the first five years after closing of the Merger allocated to that utility. If the application of that percentage to the net savings allocable to North Carolina retail would result in a greater savings sharing than that which has been allocated to North Carolina customers, then the rate reduction described in Regulatory Condition No. 73 for North Carolina retail customers will be increased to match the application of that percentage to the net savings allocable to North Carolina retail customers. Application of this methodology is intended to ensure that North Carolina retail customers receive the benefit of a "Most Favored Nation" status with regard to the sharing of net merger savings among the states named above. In no event will the application of the methodology cause North Carolina retail customers' share of net merger savings to be reduced.

75. Duke Power shall, as a condition to approval of the Merger, contribute $12,000,000 to various energy- and environmental-related and economic- and educationally-beneficial programs, said funds to be distributed as follows: $6,000,000 to Duke Power's Share the Warmth, Cooling Assistance, and Fan-Heat Relief programs; $2,000,000 for conservation and energy efficiency programs (to be submitted to the Commission for approval); $2,000,000 to the Community College Grant Fund; and $2,000,000 to NC GreenPower. These contributions shall be made by Duke Power on or before June 30, 2006. Such contributions shall not be charged to Duke Power's regulated utility operations, but shall be borne by the Company's shareholders.

76. As a condition to approval of the Merger, the North Carolina Utilities Commission shall in 2007, initiate an investigation pursuant to G.S. 62-130(d), 62-133, and 62-136(a) to determine whether Duke Power's existing rates and charges are unjust and unreasonable and, as part of this investigation, shall require Duke Power to either (1) file a general rate case (including prefiled testimony and exhibits) in North Carolina pursuant to G.S. 62-137 or (2) show cause in the form of prefiled testimony and exhibits why the Company's existing rates and charges should not be found unjust and unreasonable. The test period for this proceeding shall be the twelve-month period ending December 31, 2006, with appropriate adjustments. Duke Power shall make its filing, including a Rate Case Information Report - NCUC Form E-1, not later than June 1, 2007. Any rate changes proposed by Duke Power shall be proposed to become effective on January 1, 2008. To the extent the $117,517,000 one-year rate decrement flowed through by Duke Power to its North Carolina retail customers is deferred, with plans or provisions for amortization over future periods pursuant to Regulatory Condition No. 25, no portion of such amount, including amortization thereof, will be eligible for recovery as a component of Duke Power's North Carolina retail rates set prospectively following consummation of the Merger. In particular, no allowance for same will be included in the test-year cost of service developed for purposes of the general rate case proceeding to be instituted pursuant to this Regulatory Condition; nor will any portion of such amount be recoverable from Duke Power's North Carolina retail ratepayers by means of a rate rider or otherwise. Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. This investigation shall be consolidated with the investigation and hearing the Commission is required to undertake for Duke Power pursuant to G.S. 62-133.6(d) and (f) to review the Company's environmental compliance costs.

ATTACHMENT B

DOCKET NO. E-7, SUB 795

CODE OF CONDUCT
GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DUKE POWER, DUKE ENERGY CORPORATION, THE AFFILIATES OF DUKE POWER, AND THE NONPUBLIC UTILITY OPERATIONS OF DUKE POWER

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy Corporation and any business entity, other than Duke Power, of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy Corporation. For purposes of this Code of Conduct, Duke Energy Corporation and any business entity so controlled by it are considered to be Affiliates of Duke Power.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information: Nonpublic information that pertains to Electric Services provided by Duke Power, including but not limited to information concerning electric generation, transmission, distribution, or sales.

Customer: Any retail electric customer of Duke Power, including those served under the Commission-approved rates for Nantahala Power and Light.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, load profile, billing history, or credit history that is or has been obtained or compiled by Duke Power in connection with the supplying of Electric Services to that Customer or group of Customers.

Duke Energy Corporation: The current holding company parent of Duke Power and any successor company.

Duke Energy Shared Services: Duke Energy Shared Services, LLC, a service company Affiliate that provides Shared Services to Duke Power, Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations of Duke Power, singly or in any combination.

Duke Power: Duke Power Company, LLC, the business entity, wholly owned by Duke Energy Corporation, that holds the franchises granted by the Commission to provide Electric Services within the North Carolina service territories of Duke Power and Nantahala Power and Light, and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by Duke Power from sources other than Duke Power for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (1) the return on common equity utilized in determining such cost of capital for each good and service supplied by or from Duke Power shall equal the return on common equity authorized by the Commission in Duke Power's most recent general rate case proceeding, and (2) the cost of capital for each good and service supplied to Duke Power shall not exceed the overall cost of capital authorized by the Commission in Duke Power's most recent general rate case proceeding.

Market Value: The price at which property, goods, and services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: The mergers, the conversion of Duke Energy Corporation into a limited liability company, the restructuring transactions, and all other transactions contemplated by the Agreement and Plan of Merger between Duke Energy Corporation and Cinergy Corp.

Natural Gas Services: Natural gas sales and natural gas transportation, and other related services, including, but not limited to, metering and billing.

Nonpublic Utility Operations: All business operations engaged in by Duke Power involving activities (including the sales of goods or services) that are not regulated by the Commission, nor otherwise subject to public utility regulation at the state or federal level. This Code does not address whether or not this term includes joint or shared utility/non-utility operations such as a network for power line communications.

Personnel: An employee or other representative of Duke Power, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket No. E-7, Sub 795, or subsequent orders of the Commission and that the Commission has explicitly authorized Duke Power to take from Duke Energy Shared Services pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions, including, but not limited to, Regulatory Condition No. 20 approved in Docket No. E-7, Sub 795.

Similarly Situated: Possessing comparable characteristics, such as, with regard to Electric Services, time of use, manner of use, customer class, load factor, and relevant Standard Industrial Classification.

Utility Affiliates: The public utility operations of any Affiliate of Duke Power, including the public utility operations of PSI Energy, Inc., the public utility operations of Union Light, Heat and Power Company, and the transmission and distribution operations of The Cincinnati Gas and Electric Company.

II. GENERAL

This Code of Conduct, while not wholly inclusive or totally encompassing, establishes the minimum guidelines and rules that apply to the relationships between and among, and activities and transactions involving Duke Power and (a) Duke Energy Corporation, (b) the other Affiliates of Duke Power, or (c) Duke Power's Nonpublic Utility Operations, to the extent such relationships, activities, and transactions affect the operations or costs of utility service experienced by the public utility operations of Duke Power in its Duke Power or Nantahala Power and Light service areas. This Code of Conduct will become applicable on the date that it is approved by the Commission. This Code of Conduct is subject to such modification by the Commission as the public interest may require, including, but not limited to, changes necessitated by a change in the organizational structure of Duke Power, Duke

Energy Corporation, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry; or other changes that warrant modification of this Code.

Duke Power may request a waiver of any aspect of this Code of Conduct if exigent circumstances in a particular case justify such by filing a request for waiver with the Commission for approval.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation – Duke Power, Duke Energy Corporation, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable. Duke Power, Duke Energy Corporation, and each of the other Affiliates shall maintain separate books and records. Each of Duke Power's Nonpublic Utility Operations shall maintain separate records from those of Duke Power's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

   (a) Upon request, and subject to the restrictions and conditions contained herein, Duke Power may provide Customer Information to Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation under the same terms and conditions that such information is provided to non-Affiliates.

   (b) Except as provided in Section III.A.2.(f) below, Customer Information shall not be disclosed to any person or company, without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates or Nonpublic Utility Operations may be obtained by means of written authorization, electronic authorization or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that Duke Power retains such authorization for verification purposes for as long as the authorization remains in effect.

   (c) If the Customer allows or directs Duke Power to provide Customer Information to Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation, then Duke Power shall ask the Customer if he, she, or it would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs Duke Power to provide Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

   (d) Sections III.A.2.(a), 2.(b), and 2.(c) herein shall be permanently posted on Duke Power's website.

   (e) No Duke Power employee who is transferred to Duke Energy Corporation or another Affiliate will be permitted to copy or otherwise compile any Customer Information for use by such entity except pursuant to written permission from the Customer, as reflected by a signed Data Disclosure Authorization. Duke Power shall not transfer any employee to Duke Energy Corporation or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions established by this Section III.A.2, Duke Power may disclose Customer Information to Duke Energy Shared Services, any other Affiliate, a Nonpublic Utility Operation or a non-affiliated third party without customer consent, but only to the extent necessary for the Affiliate, Nonpublic Utility Operation or non-affiliated third party to provide goods or services to Duke Power and upon their explicit agreement to protect the confidentiality of such Customer Information.

(g) Duke Power shall take appropriate steps to store Customer Information in such a manner as to limit access to only those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) Duke Power shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

3. The disclosure of Confidential Systems Operation Information of Duke Power (referred to hereinafter as "Information") shall be governed as follows:

(a) Such Information shall not be disclosed by Duke Power to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required when disclosure to Affiliates or Nonpublic Utility Operations meets one of the following exceptions:
(i) A state or federal regulatory agency or court having jurisdiction over the disclosure of such Information requires the disclosure;
(ii) The Information is provided to employees of Duke Energy Shared Services pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153;
(iii) The Information is provided to employees of Duke Power's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service;
(iv) The Information is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of Information to be disclosed;
(v) Disclosure is otherwise essential to enable Duke Power to provide Electric Services to its Customers; or
(vi) Disclosure of the Information is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any Information disclosed pursuant to the exceptions in Section III.A.3.(a), above, shall be disclosed only to employees that need the information for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such Information must be prohibited from acting as conduits to pass the Information to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such Information.

(c) For disclosures pursuant to exceptions (v) and (vi) in Section III.A.3.(a), above, Duke Power shall include in its annual affiliated transaction report required by Regulatory Condition No. 31 approved in Docket No. E-7, Sub 795, the following information:

(i) The types of Information disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

B. Nondiscrimination

1. Duke Power employees and representatives will not unduly discriminate against non-Affiliated entities.

2. Duke Power shall not provide any preference to Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation, nor to any customers of such an entity, as compared to non-Affiliates or their customers, in responding to requests for Electric Services or in providing Electric Services. Moreover, neither Duke Power, Duke Energy Corporation, nor any of the other Affiliates will represent to any person or entity that Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. Duke Power shall apply the provisions of its tariffs equally to Duke Energy Corporation, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. Duke Power shall process all similar requests for Electric Services in the same timely manner, whether requested on behalf of Duke Energy Corporation, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of Duke Power, Duke Energy Corporation, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy Corporation or another Affiliate speaks on behalf of Duke Power; provided however, that this prohibition does not apply to employees of Duke Energy Shared Services providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of Duke Power's regulated public utility operations.

6. No personnel or representatives of Duke Power, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services exists as the result of that party dealing with Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. Duke Power shall not condition or otherwise tie the provision or terms of any Electric Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of Duke Power receives a request for information from or provides information to a Customer about goods or services available from Duke Energy Corporation, another Affiliate, or a Nonpublic Utility Operation, the employee or representative must advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy Corporation, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2 of this Code of Conduct.

C. Marketing

1. The public utility operations of Duke Power may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with its Utility Affiliates and with its Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. Duke Power may not otherwise engage in such joint activities with Affiliates without making such opportunities available to comparable third parties.

2. Neither Duke Energy Corporation nor any of the other Affiliates may use Duke Power's name or logo(s) in any communications unless a disclaimer is included that states the following:

   (a) "[Duke Energy Corporation/Affiliate] is not the same company as Duke Power, and [Duke Energy Corporation/Affiliate] has separate management and separate employees";

   (b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

   (c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from Duke Power"; and

   (d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from Duke Power."

   Nonpublic Utility Operations may not use Duke Power's name or logo(s) in any communications unless a disclaimer is included that states the following:

   (a) "[Nonpublic Utility Operation] is not part of the regulated services offered by Duke Power and is not in any way sanctioned by the North Carolina Utilities Commission";

   (b) "Purchasers of products or services from [Nonpublic Utility Operation] will receive no preference or special treatment from Duke Power"; and

(c) "A customer does not have to buy products or services from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from Duke Power."

The required disclaimer must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving Duke Power, on the one hand, and Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations, on the other, are prohibited.

2. All costs incurred by Duke Power personnel or representatives for or on behalf of Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. As a general guideline, with regard to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among Duke Power, Duke Energy Corporation, the other Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect Duke Power's operations or costs of utility service, the following conditions shall apply:

   (a) Except as otherwise provided for in this Section III.D, for untariffed goods and services provided by Duke Power to Duke Energy Corporation, an Affiliate, or a Nonpublic Utility Operation, the transfer price paid to Duke Power shall be set at the higher of Market Value or Duke Power's Fully Distributed Cost.

   (b) Except as otherwise provided for in this Section III.D, for goods and services provided, directly or indirectly, by Duke Energy Corporation, an Affiliate, or a Nonpublic Utility Operation to Duke Power, the transfer price(s) charged by Duke Energy Corporation, the Affiliate, and the Nonpublic Utility Operation to Duke Power shall be set at the lower of Market Value or Duke Energy Corporation's, the Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If Duke Power does not engage in competitive solicitation and instead obtains the goods or services from Duke Energy Corporation, an Affiliate, or a Nonpublic Utility Operation, Duke Power shall implement adequate processes to comply with this condition and ensure that in each case Duke Power's Customers receive service at the lowest reasonable cost.

   (c) Tariffed goods and services provided by Duke Power to Duke Energy Corporation, an Affiliate, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Similarly Situated Customers under the applicable tariff.

   (d) Subject to and in compliance with all conditions placed upon Duke Power by the Commission, including the Regulatory Conditions imposed in Docket No. E-7, Sub 795, and subject to a case-by-case acceptance by the Commission of an affiliate agreement, untariffed non-power, non-generation, or non-fuel goods and services provided by Duke

Power to its Utility Affiliates or by the Utility Affiliates to Duke Power, which for a single item or a single transaction amount to $100,000 or less, shall be transferred at the supplier's Fully Distributed Cost, if cost-beneficial to the recipient. Fully Distributed Cost pricing for items/transactions pursuant to this paragraph shall be limited to an aggregate annual amount of $7,500,000. Transfers above either the single item/transaction limit or the aggregate annual limit shall be priced according to Sections III.D.3.(a) and III.D.3.(b) of this Code of Conduct.

4. To the extent that Duke Power, Duke Energy Corporation, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from Duke Energy Shared Services, these Shared Services may be jointly provided to Duke Power, Duke Energy Corporation, the Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by Duke Power is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to Duke Power and is undertaken pursuant to the provisions of Regulatory Condition No. 18 approved by the Commission in Docket E-7, Sub 795. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual(s) filed with the Commission pursuant to Regulatory Condition No. 20, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. Duke Power and its Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of natural gas, coal, and electricity or ancillary services intended for resale) if such joint purchases result in cost savings to Duke Power's Customers. Duke Power, PSI Energy, Inc., and Union Light, Heat and Power Company may capture economies-of-scale in joint purchases of coal, if such joint purchases result in cost savings to Duke Power's Customers. Notwithstanding the foregoing, if any of the coal jointly purchased by Duke Power, PSI Energy, Inc., and Union Light, Heat and Power Company is transferred to or utilized by another Affiliate within 12 months of the joint purchase, Duke Power will file a notification of such with the Commission.

   All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in Duke Power's affiliated transaction reports filed with the Commission.

6. All permitted transactions between Duke Power, Duke Energy Corporation, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manuals required to be filed with the Commission pursuant to Regulatory Condition No. 20 and with affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that Duke Power incurs in assembling, compiling, preparing, or furnishing requested Customer Information or Confidential Systems Operation Information for or to Duke Energy Corporation, other Affiliates, Nonpublic Utility Operations, or non-Affiliates shall be recovered from the requesting party pursuant to Section III.D.3 of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by Duke Power in the conduct of regulated operations will not be transferred to Duke Energy Corporation, another Affiliate, or

a Nonpublic Utility Operation without just compensation and 60-days prior notification to the Commission; provided however, that Duke Power may request a waiver of this requirement from the Commission if circumstances warrant. In no case, however, shall the notice period requested be less than 20 business days.

9. Duke Power shall receive compensation from Duke Energy Corporation, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The State's existing requirements regarding affiliate transactions, as set forth in G.S. 62-153, shall continue to apply to all transactions between Duke Power, Duke Energy Corporation, and the other Affiliates.

2. The books and records of Duke Power, Duke Energy Corporation, the other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy Corporation, an Affiliate, or a Nonpublic Utility Operation to supply Duke Power with Natural Gas Services or other Fuel and Purchased Power Supply Services used by Duke Power to supply electricity, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are so supplied, Duke Power shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

1. To the extent any bill issued by Duke Power, Duke Energy Corporation, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes any charges to Customers for Electric Services and non-Electric Services from Duke Energy Corporation, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for the Electric Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. Duke Power shall establish complaint procedures to resolve potential complaints that arise due to the relationship of Duke Power with Duke Energy Corporation, its other Affiliates, and its Nonpublic Utility Operations. The complaint procedures shall provide for the following:

   (a) Verbal and written complaints shall be referred to a designated representative of Duke Power.

   (b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.

(c) Duke Power shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.

(d) Duke Power shall maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1, any complaints received through Duke Energy Corporation's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy Corporation holding company system, shall be handled in accordance with procedures established for EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint or otherwise address questions to the Commission.

CODE OF CONDUCT

ATTACHMENT A

DUKE POWER CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

Duke Power's Affiliates offer products and services that are separate from the regulated services provided by Duke Power. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

The Customer authorizes Duke Power to provide any data associated with the Customer account(s) residing in any Duke Power files, systems or databases **[or specify specific types of data]** to the following Affiliate(s) ________________________________. Duke Power will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

Duke Power offers optional, market-based products and services that are separate from the regulated services provided by Duke Power. These services are not regulated by the North Carolina Utilities Commission or the Public Service Commission of South Carolina. These products and services may be available from other competitive sources.

The Customer authorizes Duke Power to use any data associated with the Customer account(s) residing in any Duke Power files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. Duke Power will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

DOCKET NO. E-7, SUB 795

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation	)	ORDER APPROVING JOINT
for Authorization Under G.S. 62-111 to	)	RECOMMENDATION OF DUKE
Enter Into a Business Combination	)	ENERGY CAROLINAS, THE PUBLIC
Transaction With Cinergy, Corp. and for	)	STAFF AND THE ATTORNEY
Approval of Affiliate Agreements Under	)	GENERAL FOR CONSERVATION AND
G.S. 62-153	)	ENERGY EFFICIENCY PROGRAMS

BY THE COMMISSION: On May 8, 2006, Duke Power Company LLC d/b/a Duke Energy Carolinas (Duke), the Public Staff and the Attorney General, pursuant to the Commission's March 24, 2006 Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (the Order), filed a Joint Recommendation for Conservation and Energy Efficiency Programs for approval by the Commission.

In the Order, Duke was directed to contribute $2,000,000 for conservation and energy efficiency programs and to confer with the Public Staff and Attorney General to jointly develop a list of appropriate and effective conservation and energy efficiency programs for approval by the Commission.

The Order also required Duke to make such contributions for conservation and energy efficiency programs on or before June 30, 2006. Because the recommended programs will take time to develop and implement, Duke, the Public Staff and the Attorney General jointly requested that the Commission allow twelve months from the date of the approval order for Duke to complete implementation and funding of the programs. Duke also proposed that it file a report with the Commission at the conclusion of this twelve-month period summarizing the status of the programs (number of participants, final costs, etc.).

The Commission finds good cause to approve the proposed conservation and energy efficiency programs as listed in the Joint Recommendation, allow Duke twelve months from the date of this Order to complete implementation and funding of the programs, and require that Duke file a report with the Commission at the conclusion of this twelve-month period summarizing the status of the programs. This status report is due on or before July 2, 2007.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of May, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr052206.07

DOCKET NO. E-2, SUB 891

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by Progress Energy Carolinas, Inc., for Approval to Reallocate Decommissioning Fund Contributions	)))	ORDER APPROVING REALLOCATION OF DECOMMISSIONING FUND CONTRIBUTIONS

BY THE COMMISSION: On July 6, 2006, pursuant to G.S. 62-30, 32, and 35 and Commission Rule R1-5, Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), filed an application for approval to reallocate decommissioning fund contributions.

On September 7, 1995, the Commission issued an Order in Docket No. E-2, Sub 682, which clarified the following annual amounts of North Carolina retail nuclear decommissioning expense established for ratemaking purposes in Docket No. E-2, Sub 537:

Unit	1994	1995	1996 and thereafter
Brunswick Unit 1	$ 5,094,013	$ 5,156,742	$ 5,156,742
Brunswick Unit 2	6,361,524	6,442,619	6,497,337
Harris Unit 1	3,349,510	3,369,324	3,369,324
Robinson Unit 2	5,346,661	5,450,711	5,509,554
Total	$ 20,151,708	$ 20,419,396	$ 20,532,957

The Order did not impact PEC's rates.

The Order stated that the decommissioning charges approved in Docket No. E-2, Sub 537, may be modified based on the Commission's findings in the then pending generic decommissioning docket, Docket No. E-100, Sub 56. The Commission issued an Order approving decommissioning guidelines in Docket No. E-100, Sub 56, on November 3, 1998.

By application filed on December 6, 1999, and amended on April 16, 2001, in Docket No E-2, Sub 756, PEC requested approval to reallocate decommissioning fund contributions based on updated decommissioning cost studies, trustee earnings reports, and associated revenue requirements/expense calculations filed in 1999.

On June 6, 2001, the Commission issued an Order in Docket No. E-2, Sub 756, stating that for 2001 and thereafter, North Carolina retail per unit amounts of annual nuclear decommissioning expense established for ratemaking purposes are:

Unit	Annual Expense	% Total
Brunswick Unit 1	$ 4,934,785	24%
Brunswick Unit 2	3,672,213	18%
Harris Unit 1	4,204,972	20%
Robinson Unit 2	7,720,987	38%
Total	$ 20,532,957	100%

On December 30, 2004, in Docket No. E-100, Sub 56, PEC filed updated decommissioning cost studies, and on July 20, 2005, based on the results of the updated decommissioning cost studies and trustee earnings reports, PEC filed a Decommissioning Cost and Funding Report, including the associated revenue requirements/expense calculation. Based on the cost studies and reports, PEC calculated the following per unit North Carolina retail revenue requirements:

Unit	Revenue Requirements	% Total
Brunswick Unit 1	$ 686,523	4%
Brunswick Unit 2	430,800	2%
Harris Unit 1	11,108,093	56%
Robinson Unit 2	7,612,846	38%
Total	$ 19,838,262	100%

Because the total revenue requirement of $19,838,262 varied by only (3.4%) from the annual decommissioning expense of $20,532,957 currently being recorded on PEC's books, which is less than the 15% variance set forth in Guideline No. 5 in Docket No. E-100, Sub 56, PEC did not request that the total annual decommissioning expense for ratemaking purposes be decreased. However, because the revenue requirements for Brunswick Unit 1, Brunswick Unit 2, and Harris Unit 1 as individual units varied so widely from the existing allocation, PEC is requesting in the current docket that, for 2006 and thereafter until such time as the Commission orders a change, the annual decommissioning expense of $20,532,957 be reallocated among the various units at the ratio of the updated unit amounts to the updated total revenue requirement of $19,838,262. The resulting per unit amounts are as follows:

Unit	Annual Expense	% Total
Brunswick Unit 1	$ 710,564	4%
Brunswick Unit 2	445,886	2%
Harris Unit 1	11,497,075	56%
Robinson Unit 2	7,879,432	38%
Total	$ 20,532,957	100%

According to PEC, the reallocation is necessary to reflect updated decommissioning contributions needed to decommission the individual units.

Commission approval of the reallocation is also needed before PEC can use it when determining the amount of contributions to be deposited into the external qualified and external non-qualified trust funds in accordance with Section 468A of the 1986 Internal Revenue Code, as amended. The Section 468A guidelines and requirements are based on per unit decommissioning totals. A utility can deduct, for federal income tax purposes, its contributions to a qualified external trust for the taxable year in which the annual contribution is made to the trust, but the amount of its annual contributions is limited by Section 468A. In general, the maximum annual contribution a utility can deposit into a qualified external trust is equal to the lesser of (1) the amount of decommissioning costs included in its cost of service for ratemaking purposes or (2) the ruling amount, an annuity approved by the Internal Revenue Service that, over time, will accumulate to equal the portion of future decommissioning costs allocable to the remaining life of the nuclear unit as of 1984, the date Section 468A was enacted. In addition to a tax deduction for contributions to a qualified external trust, earnings on funds deposited in a qualified external trust are taxed at a lower rate for federal income tax purposes than funds deposited in a non-qualified external trust. Therefore, it is in PEC's and its customers' best interest to maximize the contributions made to the qualified external trust. PEC's rates will not be impacted by the request for reallocation.

The Public Staff brought this matter before the Commission at its Regular Staff Conference on September 11, 2006. The Public Staff stated that it had reviewed PEC's application for approval to reallocate nuclear decommissioning fund contributions and recommended that the Commission approve PEC's application.

Based on the foregoing, the Commission concludes that the reallocation of decommissioning fund contributions among units as requested by PEC is appropriate to reflect an update of decommissioning contributions needed to decommission the units.

IT IS, THEREFORE, ORDERED as follows:

1. That PEC's application for approval to reallocate decommissioning fund contributions among its nuclear units is approved.

2. That, effective beginning January 1, 2006 and thereafter until such time as the Commission orders a change, the North Carolina retail per unit amounts of annual nuclear decommissioning expense established for ratemaking purposes are:

Unit	Annual Expense
Brunswick Unit 1	$ 710,564
Brunswick Unit 2	445,886
Harris Unit 1	11,497,075
Robinson Unit 2	7,879,432
Total	$ 20,532,957

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of September, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah091306.02

DOCKET NO. E-7, SUB 817

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Power Company LLC,	)	
Nantahala Area d/b/a Duke Energy -	)	ORDER APPROVING
Nantahala Area for Approval of Purchased	)	PURCHASED POWER
Power Cost Rider Schedule "CP"	)	COST RIDER

BY THE COMMISSION: On July 10, 2006, Nantahala Power and Light, now known as Duke Power Company LLC, Nantahala Area d/b/a Duke Energy – Nantahala Area (Nantahala or the Company), filed an application to adjust the purchased power cost component of its electric rates for the period September 2, 2006, through September 1, 2007, per Commission Order dated October 28, 1996, in Docket No. E-13, Sub 171. By letter dated August 10, 2006, Nantahala filed an Updated Exhibit A to its filing showing the actual data for over/under collections for the full test period.

The factor proposed by the Company to be included in rates for the period ending at midnight on September 1, 2007, is an increment of $0.0436 (including gross receipts tax) and consists of two components. The first is an increment of $0.0432 to recover the estimated purchased power costs for the period September 2, 2006, through September 1, 2007. The second is an increment of $0.0004 to collect the under-recovery of purchased power costs for the period August 2005 through July 2006.

Additionally, the factor has equivalent demand and energy components, which are included in Schedules IT and OPTN, the industrial time-of-use schedule and the net metering time-of-use demand schedule respectively. The time-of-use demand charge is $10.05 per kW (including gross receipts tax). The time-of-use energy charge proposed by the Company is $0.0207 per kWh (including gross receipts tax, consisting of $0.0203 to recover estimated purchased power costs for the period September 2, 2006, through September 1, 2007, and $0.0004 to recover the under-recovery of purchased power costs for the period August 2005 through July 2006).

The Public Staff presented this item at the Commission Staff Conference on August 21, 2006, stating that it had reviewed the Company's filing and recommended that the factors set forth above be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That Nantahala's Purchased Power Cost Rider, Schedule "CP," Attachment A to this Order, is allowed to become effective for bills rendered on and after September 2, 2006, and expires at midnight on September 1, 2007.

2. That the Purchased Power Cost Rider is allowed to become effective without prejudice to the right of any party to take issue with the rider in a general rate case.

3. That Nantahala shall give appropriate notice to its retail customers of the Purchased Power Cost Rider approved herein. Such notice shall be by bill insert for the billing cycle beginning September 2, 2006. A copy of the notice shall be filed with the Chief Clerk of the North Carolina Utilities Commission within fifteen (15) working days of the date of this Order.

4. That Nantahala shall file with the Chief Clerk within five (5) working days of the date of this Order, copies of its retail rate schedules appropriately adjusted to include the purchased power cost rider approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Ah082106.02

ATTACHMENT A

Duke Power Company, LLC, Nantahala Area
d/b/a Duke Energy – Nantahala Area

SCHEDULE CP (NC)
PURCHASED POWER COST RIDER

APPLICABILITY (North Carolina Nantahala Area only)
The customer's bill rendered for each month September 2, 2006, through September 1, 2007, shall be adjusted by a charge of 4.36 cents per kWh, including revenue-related taxes, as determined to be appropriate by the North Carolina Utilities Commission. This energy charge is included in the monthly energy rate stated on the appropriate rate schedules. The demand and energy time-of-use components of this charge are included in the demand and energy rates of Schedules IT and OPTN, which apply only to non-residential time-of-use customers.

This rate is determined as follows:

	All Schedules (except IT, OPTN)	Schedules IT, OPTN Demand	Schedules IT, OPTN Energy
Factor to recover estimated purchased power costs for the billing period September 2006-September 2007	4.32 cents per kWh	$10.05 per KW	2.03 cents per kWh
Experience modification factor to reflect actual results for the period August 2005-July 2006	0.04 cents per kWh		0.04 cents per kWh
TOTAL RATE	4.36 cents per kWh	$10.05 per kW	2.07 cents per kWh

Effective for bills rendered on and after September 2, 2006.
NCUC Docket No. E-7, Sub 817
Order dated August ___, 2006

(Page 1 of 1)

DOCKET NO. G-9, SUB 519

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas Company, Inc., to Modify Tariffs and Service Regulations	)))	ORDER APPROVING MODIFICATIONS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, July 18, 2006, at 9:30 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Commissioners Sam J. Ervin, IV; James Y. Kerr, II; William T. Culpepper, III; and Howard N. Lee.

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, Bank of America Corporate Center, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202-4003

For the Using and Consuming Public:

Gina Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For Carolina Utility Customers Association, Inc.:

James P. West, West Law Offices, PC, Suite 2325, Two Hannover Square, 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

BY THE COMMISSION: On February 22, 2006, Piedmont Natural Gas Company, Inc. (Piedmont or the Company) filed a notice of its intent to extend the date by which its customers eligible to receive service under Piedmont's Rate Schedules 103, 104, 113, and 114 are required to make an annual election between sales and transportation service. The stated purpose of Piedmont's extension was to permit time for the preparation and filing of tariff revisions relating to Third-Party Agent (TPA) transactions on the Piedmont system. The Commission allowed Piedmont's extension of time upon which annual elections must be made, without prejudice to the rights of parties to take any position on the substance of Piedmont's follow-up tariff filing, pursuant to its February 27, 2006 Order Allowing Extension For Annual Election Of Sales Or Transportation Service.

On February 28, 2006, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was granted by Commission Order dated March 2, 2006.

On March 16, 2006, Piedmont filed its Petition seeking approval of certain modifications to its transportation rate schedules and service regulations in order to establish greater control over the activities of and risks posed by TPAs operating on Piedmont's system on behalf of industrial transportation customers.

On March 21, 2006, the Commission issued its Order Providing for Notice and Comments in this proceeding. In that Order, the Commission adopted mechanisms designed to ensure that interested parties were provided notice of Piedmont's proposals and allowed for the filing of initial and reply comments on Piedmont's tariff modification proposals.

On April 11, 2006, CUCA filed its comments on Piedmont's tariff modification proposal in which CUCA indicated its opposition to Piedmont's proposed TPA creditworthiness provisions and further proposed that Piedmont be required to provide certain intra-month operational data to its customers.

On April 18, 2006, Amerada Hess Corporation (Amerada Hess) filed a petition to intervene, which was granted by Commission Order dated April 25, 2006.

On April 28, 2006, Piedmont filed its Reply Comments addressing CUCA's concerns and asking that its proposed tariff modifications be approved by the Commission.

On May 19, 2006, the Commission issued its Order Scheduling Hearing in this proceeding in which it noted that Piedmont and CUCA continued to maintain opposing positions on the relative need for and propriety of certain of Piedmont's proposed tariff modifications and established a hearing date for this matter of July 18, 2006, at 9:30 a.m. in the Commission Hearing Room.

On June 9, 2006, Piedmont filed the direct testimony of Frank Yoho in support of its proposed tariff modifications.

On June 29, 2006, CUCA filed the direct testimony of Kevin W. O'Donnell in opposition to Piedmont's proposed tariff modifications.

On July 11, 2006, Piedmont filed the rebuttal testimony of Frank Yoho.

No other party filed testimony.

On July 18, 2006, this matter came on for hearing as scheduled.

Based on the testimony and exhibits received into evidence and the record in this matter as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a public utility as defined in Chapter 62 of the North Carolina General Statutes.

2. Piedmont is engaged in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. Under Piedmont's existing tariffs, Piedmont's transportation customers have the right, within limits, to maintain intra-month imbalances on the Piedmont system. These imbalances are created when a transportation customer delivers either more or less gas to Piedmont on any given day than the customer actually consumes on that day.

4. The purpose of this imbalance flexibility is to avoid penalizing individual customers for slight variations between projected usage of gas and actual usage on a daily basis.

5. The right to maintain these imbalances is subject to Piedmont's operational needs and abilities and may be restricted by the Company if system integrity or service to other customers is threatened.

6. Under Piedmont's tariff structure, these intra-month imbalances are carried forward from day-to-day and any unresolved imbalances remaining at the end of each month are "cashed-out" pursuant to terms contained in Piedmont's transportation tariffs.

7. Under Piedmont's existing tariffs, a transportation customer has the right to appoint a TPA to act as agent for the customer in making nominations for transportation service, in managing and resolving monthly imbalances, and for billing purposes.

8. TPAs nominated by Piedmont's customers to perform one or more of these functions do so under terms and conditions agreed to in private contracts between the customer and the TPA, the terms of which are not known by or disclosed to Piedmont.

9. TPAs are not customers of Piedmont inasmuch as they use no gas provided or delivered by Piedmont for any purpose. Instead, they act as agents for Piedmont's customers and attempt to extract value out of providing service to customers, including, in some cases, the provision of upstream gas supplies to Piedmont on behalf of their customers. As a result of this fact, their motivations in scheduling and delivering gas can be somewhat different from those of their customers, who are primarily concerned with the availability of gas for manufacturing or process purposes.

10. TPAs are nominated by execution of an Agency Authorization Form attached to Piedmont's transportation tariffs. This form, which is also executed by the TPA, establishes joint and several liability of the customer and the TPA for any amounts due Piedmont under its tariffs for the transportation service provided by Piedmont at the direction of the TPA acting as the customer's agent.

11. Other than as created by this form, there is no legal relationship established between Piedmont and the TPAs operating on its system.

12. TPAs operating on Piedmont's system may represent a large number of individual customers, whose transportation volumes are aggregated by the TPA for nomination and imbalance management purposes.

13. As a result, the nomination and delivery activities of a single TPA can result in very substantial aggregate nominations and imbalances on the Piedmont system in a very short period of time. The impact of this phenomenon can be magnified by the extreme volatility and high prices present in today's natural gas commodity market.

14. Where such imbalances result in transportation customers taking more gas from Piedmont than their TPA has caused to be delivered to Piedmont, then Piedmont must utilize its own system assets (and sometimes upstream assets) to maintain service to these customers.

15. In extreme cases, substantial shortfalls in deliveries can result in potential operational harm to Piedmont and/or the diversion and depletion of assets with limited availability which are designed to meet the peak-day needs of Piedmont's sales customers.

16. This past winter, Piedmont experienced problems with a TPA that represented over 120 individual transportation customers. That TPA failed to nominate or deliver any gas to Piedmont over a three-day weekend period while all of its customers continued to burn gas during that period.

17. This situation resulted in the creation of an immediate and serious imbalance on the Piedmont system, equal to approximately 80,000 dekatherms, which posed a financial threat to customers and both an operational and financial threat to the Company.

18. Piedmont immediately contacted the TPA, which told Piedmont that its supply arrangements had fallen through and that it would make up the imbalance in the next few days. Piedmont continued to try to work with the TPA for a few more days to determine if it could make up the imbalance, but then suspended that TPA's operations on the Piedmont system when the imbalance was not made up.

19. This TPA was placed into involuntary receivership shortly thereafter and filed for bankruptcy protection a short time later, leaving an unresolved and substantial imbalance. The scale of this imbalance, which totaled approximately $1.2 million (exclusive of penalties), created a material credit risk for Piedmont and a substantial unresolved liability for the customers served by this TPA.

20. Over the next approximately eight (8) months, Piedmont pursued its customers for their proportional share of the unresolved imbalance liability (Piedmont was precluded by federal bankruptcy laws from pursuing the TPA). According to Piedmont, a number of its customers initially denied liability for these amounts, notwithstanding the clear provisions of the Agency Authorization Form establishing joint and several liability for these amounts. Ultimately, after a substantial expenditure of time and outside attorney's fees, and, in some cases, in the face of a threat of pending service disconnection, each of Piedmont's customers agreed to make payment for their share of the imbalance.

21. For many of these customers, the obligation to pay Piedmont for their share of the aggregate imbalance represented paying twice for the gas they used inasmuch as they had previously prepaid the TPA for that gas.

22. Following this incident and in recognition of the increased risk posed by the prevailing volatility and high prices in commodity gas markets, Piedmont proposed certain modifications to its tariffs meant to address weaknesses identified by last winter's events relating to the activities of TPAs on its system. These weaknesses included the lack of limits on permissible TPA aggregate imbalances, the need for some sort of creditworthiness provisions to protect Piedmont and its customers, and clarification of some aspects of its existing tariff language. In implementing these provisions, Piedmont also sought to create a direct contractual and tariff relationship between itself and the TPAs operating on its system.

23. Piedmont's proposed tariff revisions did not change or modify the substantive rights or tariff terms applicable to its transportation customers. Instead, according to Piedmont, the revisions were intended to place reasonable limits on the ability of TPAs to create large aggregate imbalances

on Piedmont's system and to provide Piedmont, through its proposed creditworthiness requirements, with a three-to-four-day safe harbor during which it could work with TPAs to resolve imbalance problems without serious economic threat to Piedmont or its customers.

24. Piedmont's initial filing indicated that, in its opinion, these proposed tariff changes were limited in nature. Piedmont further indicated that it had consulted with the Public Staff, marketers active on its system, and representatives of its industrial transportation customers prior to filing and that it had incorporated suggestions from these entities into its proposals.

25. In response to preliminary comments filed by CUCA in this proceeding, Piedmont further modified its proposed tariff changes to (a) create a "small TPA" exclusion from its creditworthiness requirements applicable to TPAs whose aggregate creditworthiness obligations total $100,000 or less and (b) provide copies of formal notices issued by Piedmont to TPAs, in written or electronic form, to customers served by that TPA.

26. No party other than CUCA objected to any aspect of Piedmont's proposed tariff revisions.

27. CUCA (a) objected to Piedmont's proposed TPA creditworthiness requirements, (b) objected to the application of those requirements to TPAs that do not take title to gas, (c) proposed that Piedmont be required to provide information regarding a TPA's performance and all notices to a TPA to its customers, and (d) proposed that Piedmont be required to permit a customer to make mid-month changes to its authorized TPA at the Customer's volition.

28. Piedmont opposed CUCA proposals.

29. Piedmont's proposed tariff modifications are limited in nature and reasonably required to address the potential for operational and economic harm to Piedmont's customers and Piedmont itself arising from the operations of TPAs on Piedmont's system.

30. Piedmont's proposed TPA creditworthiness provisions are reasonable, the creditworthiness mechanisms proposed are not materially different from TPA mechanisms previously approved by the Commission, and the TPA creditworthiness provisions will not be unreasonably costly to customers.

31. There is no basis to distinguish between TPAs that take title to gas and those that do not take title to gas in the application of Piedmont's revised tariff provisions.

32. It is not reasonable or appropriate to require Piedmont to disclose commercial details of aggregate TPA operations to TPA customers, but it is reasonable to require Piedmont to provide contemporaneous copies to customers of all official notices issued by Piedmont to TPAs serving such customers.

33. It is not reasonable to require Piedmont to permit transportation customers to make *ad hoc* changes to TPAs on an intra-month basis.

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

The evidence supporting these findings of fact is contained in the Petition (which, along with the attached tariffs, is designated as Exhibit FHY-1) and in the official files and records of the Commission. These findings are essentially informational and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-6

The evidence supporting these findings of fact is contained in Piedmont's Petition and attached tariffs and in the testimony of Piedmont witness Yoho.

As is reflected in Exhibit FHY-1, Piedmont's existing transportation tariffs (Rate Schedule 113 – Large General Transportation Service, Rate Schedule 114 – Interruptible Transportation Service, Rate Schedule T-5 – Transportation Service to Large Float Glass Furnaces, Rate Schedule T-7 – Transportation Service to Large Aluminum Operations, Rate Schedule T-10 – Transportation Service to Military Installations with Contract Demand in Excess of 5,000 DT per day, and Rate Schedule T-12 – Transportation Service to Military Installations in Onslow County) each permit customers to maintain a reasonable degree of flexibility in the management of intra-month imbalances on the Piedmont system. Intra-month imbalances occur when the quantity of gas delivered to Piedmont on behalf of a transportation customer differs from the quantity of gas actually consumed by that customer on that day. Piedmont's tariffs do not prescribe specific limits on intra-month imbalances, but they do place an obligation on transportation customers to manage their nominations and receipts so as to correct imbalances as they occur. Piedmont's tariffs also provide the Company with authority to limit such imbalances where necessary to avoid operational harm.

As is evident from Piedmont's tariffs, intra-month imbalances are carried forward on a day-to-day basis and any imbalance remaining at the end of a month is cashed out pursuant to the formulas set forth in Piedmont's tariffs.

These facts regarding the structure of Piedmont's existing transportation tariffs are evident from the face of its tariffs and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-11

The evidence supporting these findings of fact is contained in Exhibit FHY-1 and the testimony of Piedmont witness Yoho.

As is reflected in Piedmont's Exhibit FHY-1, the Company's transportation rate schedules permit each transportation customer to "authorize an Agent to act on its behalf with respect to the nominations, imbalance resolution, and/or billing under this Rate Schedule by executing an Agency Authorization Form . . . ."

Piedmont's Petition and the testimony of Piedmont witness Yoho both indicated that TPAs are not customers of Piedmont and, instead, are selected by Piedmont's customers to act as their agents for purposes of making nominations, managing imbalances, and billing. Mr. Yoho's testimony indicated that TPAs may have economic interests in particular circumstances that vary from those of the customers they serve and that those interests can lead TPAs to potentially engage in behavior that is not consistent with the efficient operation of Piedmont's system.

As is reflected in Exhibit FHY-1, the Agency Authorization Form by which transportation customers designate TPAs establishes the joint and several liability of both the customer and the TPA for amounts that may become due to Piedmont. This form is the only document establishing a legal relationship between Piedmont and a TPA under Piedmont's existing tariff structure.

No other party presented evidence on these matters.

Based on this evidence the Commission concludes that Piedmont transportation customers have the ability to designate TPAs as their agents for nomination, imbalance management, and billing purposes, but that those TPAs are not customers of Piedmont and may have different economic interests from either their customers or Piedmont. The Commission further concludes that the current Agency Authorization Form is the only document establishing a direct contractual relationship between a TPA and Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-15

The evidence supporting these findings of fact is contained in Exhibit FHY-1 and the testimony of Piedmont witness Yoho.

In his testimony Mr. Yoho indicated that, because TPAs can aggregate volumes for many customers, "their impact on the Piedmont system can be substantially larger than that of individual customers." By way of example, Mr. Yoho testified that one TPA this past winter represented over 120 individual transportation customers. Mr. Yoho also testified that the volatility now prevailing in the natural gas commodity market exacerbates the risk of harmful TPA behaviors because of the potential for very high per dekatherm costs of gas. In order to deal with serious aggregate imbalances created by a TPA, without curtailing service to its customers, Piedmont may be required to lean heavily on its own system assets and/or upstream storage and transportation assets, which were procured to serve other higher priority customers under peak-day conditions. Mr. Yoho described the nature of the potential harm that could result from aggregate TPA imbalances as both operational and financial. The operational harm is the result of possible system integrity issues -- both near term and long term -- resulting from large imbalances. The possible financial harm results from the fact that a large negative imbalance (where customers have taken much more gas off of Piedmont's system than their TPA has delivered) effectively constitutes an involuntary loan of gas by Piedmont to those customers. Under Piedmont's existing tariffs, there is no security to assure repayment of this loan by the TPA.

No other party provided evidence on these issues.

Based on this evidence, the Commission concludes that, under Piedmont's existing tariff structure, TPAs who have the ability to aggregate the quantities of many transportation customers have the capability to create large and potentially problematic imbalances on the Piedmont system.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-19

The evidence supporting these findings of fact is contained in the Petition and the testimony of Piedmont witness Yoho.

In its Petition, Piedmont indicated that, last December, a TPA which was performing nomination and imbalance resolution functions for 122 individual transportation customers on the Piedmont system, failed to make any nominations over a three-day weekend. During this period, the customers on whose behalf the TPA was acting as agent consumed more than 80,000 dekatherms of natural gas, notwithstanding the fact that no quantities of natural gas were delivered to Piedmont on behalf of these customers. In order to provide service to these transportation customers, Piedmont was forced to draw on its firm contractual upstream supplies and storage inventories. As a result of these events, an immediate and significant imbalance was created which threatened the ability of the Company to continue service to these customers (and its firm sales customers) and exposed Piedmont and its customers to well over a million dollars in gas costs associated with this imbalance.

According to Piedmont's undisputed account, it immediately contacted this TPA and attempted to work with it for several more days in an effort to reduce or eliminate the imbalance created over this weekend. The TPA assured Piedmont that it would resolve the imbalance by delivering additional volumes to Piedmont, but failed to do so for several days. Ultimately, Piedmont suspended the ability of this TPA to conduct business on its system. Shortly thereafter, the TPA was forced into involuntary receivership and then subsequently filed for federal bankruptcy protection. At the time it was suspended from operating on Piedmont's system, the TPA owed more than $1.2 million in imbalance cash-out costs (exclusive of penalties).

No other party presented evidence on these matters.

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

The evidence supporting these findings of fact is contained in the testimony of Piedmont witness Yoho.

Mr. Yoho testified that Piedmont had substantial difficulty collecting the allocated share of the TPA imbalance liability created last fall from the customers on whose behalf that TPA was acting. This was true notwithstanding the fact that these customers had received and used the gas comprising the imbalance and had expressly agreed to be liable for any such imbalance. Initially, and notwithstanding the plain language of the Agency Authorization Form establishing joint and several liability for the imbalance, many of these customers denied liability to Piedmont for their share of the imbalance. After substantial efforts and the incurrence of significant expense (both internally and externally) Piedmont was recently able to obtain agreement from its customers to pay their allocated share of the imbalance. In several cases where customers had prepaid the TPA for December gas, this resulted in customers actually paying twice for the gas they used in the early part of last December.

No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that, in cases where large imbalances are created by TPAs, economic risks exist to both Piedmont and its customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-25

The evidence supporting these findings of fact is contained in Exhibit FHY-1, Piedmont's April 28, 2006 Reply Comments, and in the testimony of Piedmont witness Yoho.

In its Petition, Piedmont indicated that, in the aftermath of the harmful TPA activity on its system last December, it determined that modifications to its tariffs were necessary in order to protect against similar occurrences in the future where substantial intra-month imbalances might be created by TPAs. In its filing, Piedmont proposed (a) to make certain clarifying changes to its Agency Authorization Form, (b) to adopt a new Customer Agent Agreement (CAA) form, and (c) to require TPAs to execute the new CAA in order to be eligible to conduct business on the Piedmont system. As is evident from Piedmont's proposed tariffs, the primary impact of the proposed CAA is to require the establishment of creditworthiness by TPAs, through a variety of possible means, equivalent to approximately three to four days of average nominations and to restrict aggregate intra-month TPA imbalances to a similar level. According to Mr. Yoho, this would give Piedmont a three-to-four-day window within which to work with TPAs who were creating large imbalances before Piedmont and its customers would be at risk of harm from inappropriate TPA behavior. Piedmont's proposed tariff changes would also create a direct contractual relationship between Piedmont and TPAs operating on its system. Finally, Piedmont's proposed tariff revisions would not change the tariff rights of individual transportation customers under its existing tariffs.

As reflected in Piedmont's Petition, these proposed tariff changes are limited in nature and were presented to Piedmont's customers, TPAs operating on its system, CUCA, and the Public Staff before they were filed with the Commission. In that process, Piedmont made changes to its filing based on comments received from CUCA. Piedmont offered further changes to its proposed tariff revisions in its April 28, 2006 Reply Comments, relating to a small-TPA exclusion from creditworthiness requirements where that requirement would be $100,000 or less and an agreement to provide customers with copies of all official notices issued to the TPAs acting as their agent.

No other party presented evidence on these issues.

Based on the foregoing, the Commission concludes that Piedmont's proposed tariff changes are limited in nature and seek to mitigate the aggregate potential impact of improper TPA behavior on its system without changing the existing tariff rights of transportation customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26-28

The evidence supporting these findings of fact is contained in the Commission's records in this proceeding and in the testimony of CUCA witness O'Donnell and Piedmont witness Yoho.

In its March 21, 2006 Order Providing for Notice and Comments in this proceeding, the Commission directed the Clerk to serve a copy of its order on all parties on the Commission's natural gas service list. In addition, the Commission directed Piedmont to serve a copy of the same document on all TPAs operating on its system and to file a certificate of service with the Commission attesting to the completion of that task by March 28, 2006. On March 24, 2006, Piedmont filed a certificate with the Commission indicating that it had served a copy of the Commission's order on all TPAs active on its system and identifying thirty-two (32) entities that met that description. In this case, only two parties have sought intervenor status. One is CUCA and the other is Amerada Hess, a large TPA operating on Piedmont's system (and nationally).

In this proceeding, no TPA has posed any objection to Piedmont's proposed tariff modifications. In fact, only CUCA -- an entity that represents industrial end-users -- has posed any objection to Piedmont's proposals. As is reflected in the testimony of CUCA witness O'Donnell, CUCA objected to Piedmont's proposed TPA creditworthiness requirements as too costly and overly intrusive of the relationship between TPA and customer, and further objected to the application of those requirements to TPAs that do not take title to gas. Mr. O'Donnell also proposed that Piedmont be required to provide information relating to the operation of TPAs on the Piedmont system as well as copies of notices from Piedmont to the TPA. Finally, Mr. O'Donnell proposes that customers be permitted to make *ad hoc* changes to TPAs on an intra-month basis.

Piedmont opposed CUCA's positions.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29-30

The evidence supporting these findings of fact is contained in the Petition and in the testimony of Piedmont witness Yoho and CUCA witness O'Donnell.

Piedmont's evidence demonstrated that TPAs, who have the ability to aggregate nominations for many industrial customers, are able to create large imbalances on the Piedmont system in a very short period of time. These imbalances present both operational and economic risks to Piedmont and its customers (including the customers served by the TPA). This risk is more significant now than it has been in the past because of the unprecedented per dekatherm cost of natural gas on the commodities market and the extreme volatility in that market experienced in the recent past. These risks were realized in the case of one TPA this past winter when that TPA (acting as agent for more than 120 industrial transportation customers) failed to nominate or deliver gas for its customers. This resulted in the creation of a large imbalance in just a three-day period. This imbalance required Piedmont to utilize upstream capacity and storage assets which were intended to support peak-day service to high priority sales customers in order to avoid a curtailment of service to the customers served by this TPA. These events also caused Piedmont to incur substantial internal and external expenses in an effort to recover the imbalance charges from Piedmont's customers, many of whom initially denied liability for these costs and/or were required to pay for the gas they used last December twice.

In recognition of the risks presented by TPAs capable of aggregating the quantities utilized by a large number of individual transportation customers, Piedmont proposed tariff modifications which will require TPAs operating on its system to enter into a direct contractual relationship with Piedmont pursuant to which those TPAs must establish creditworthiness and are restricted in the level of aggregate intra-month imbalance that they can exceed.

As was noted above, no TPAs active on the Piedmont system have objected to Piedmont's proposal.[1] CUCA did not object to the establishment of a contractual relationship between Piedmont and the TPAs and did not object to the proposed restrictions in the level of aggregate intra-month imbalances that the TPAs could exceed. However, Mr. O'Donnell testified that the costs incurred by the TPAs due to the creditworthiness requirements in Piedmont's proposed CAA will be passed through to Piedmont's customers. CUCA further objected because the creditworthiness requirements are, in its view, too costly and intrusive of the relationship between a TPA and its customer.

One mechanism for establishing creditworthiness listed in the Piedmont CAA was a letter of credit. The cost of establishing creditworthiness for an individual industrial customer with a letter of

[1] The Commission notes that Piedmont's proposed tariff revisions at issue in this proceeding, have been approved in both South Carolina and Tennessee without objection by any party.

credit was the subject of disagreement. Mr. O'Donnell testified that he was informed that establishing creditworthiness with a letter of credit to cover an individual customer could cost as much as $30,000 a year. He argued that such costs would be passed on to the industrial customers and would be prohibitively expensive for those customers.

Both Piedmont witness Yoho and CUCA witness O'Donnell seemed to be in general agreement as to the percentage fee for a letter of credit. Mr. Yoho testified that Piedmont's treasury and financial groups told him that the fee for a typical letter of credit would be a hundred basis points. Mr. O'Donnell testified that credit analysts he had talked to stated that the cost could range from forty basis points to over two hundred basis points, depending on a number of factors, but agreed that a hundred basis points was "in the ball park."

The substantive point of disagreement was whether the letter of credit needed to be sufficient to cover the dollar amount of Piedmont's CAA credit requirement based on three days of throughput, as stated by Mr. Yoho, or whether it would have to cover the throughput for an entire year, as stated by Mr. O'Donnell. Mr. Yoho testified, based on information acquired from finance experts at Piedmont, that the annual cost of obtaining a letter of credit for a large Piedmont transportation customer would be in the range of $200 In an example of the cost of a letter of credit, Mr. Yoho testified that a large customer might consume 500 dekatherms of gas a day at a price of $10 per dekatherm and, using the three days of volume described in the CAA, would yield "about $200 a year on a $2 million gas bill."

Mr. O'Donnell asserted that the cost of establishing creditworthiness with a letter of credit would be $30,000 per year. Mr. O'Donnell was not the source of the $30,000-a-year cost estimate and nowhere in his testimony did he identify the source of that estimate other than to say it was a marketer. He testified that he did not show his source the Piedmont CAA, but rather asked a "generic question" about the cost of a letter of credit and was told it was "one percent of throughput." Whether the source understood that Piedmont was requiring credit to cover approximately three days is unclear from Mr. O'Donnell's testimony. As such, it is impossible for the Commission to evaluate the validity of that estimate, or even to know how it was calculated.

Mr. O'Donnell agreed that, using the assumptions put forward by Mr. Yoho (500 dekatherms per day of consumption at $10 per dekatherm), the CAA formula would yield a dollar amount of $18,750 for three days of throughput. While Mr. Yoho's testimony estimated that a letter of credit would cost one percent of $18,750, or $187.50, Mr. O'Donnell maintained that, if the TPA were to use a letter of credit, the issuer was "going to be asking for what's your annual throughput." Mr. Yoho testified that an escrow deposit would be cheaper than buying a letter of credit if the cost was of the nature described by Mr. O'Donnell.

The Commission has carefully considered Mr. O'Donnell's testimony on the question of the cost of a letter of credit and does not find it to be persuasive. In this situation, the Commission concludes that it should not base its decision on this estimate.

The Commission has carefully considered the testimony of Mr. O'Donnell and of Mr. Yoho on the cost of meeting the creditworthiness requirement of the CAA and finds Mr. Yoho's testimony to be more persuasive. As Piedmont's proposed tariffs state, and Mr Yoho confirmed, letters of credit are not the only mechanism available to establish creditworthiness. As the situation allows, creditworthiness can be established through no-cost parental guarantees or other mechanisms acceptable to Piedmont.

The Commission notes that, should CUCA's fears be realized and the cost prove to be prohibitive, a complaint proceeding could be initiated with this Commission.

Mr. O'Donnell also drew a distinction between prior TPA creditworthiness provisions approved by the Commission for NUI Corporation and Piedmont's proposal in this docket. Mr. O'Donnell testified, "The Commission has addressed third-party creditworthiness issues in the past. In Docket No. G-3, Sub 235, the Commission approved plan by NUI Carolina Gas to order marketers to provide certain financial records, and other written documents...to prove their financial creditworthiness. If the marketer was not able to maintain the creditworthiness, NUI was then permitted to require a payment in advance, a letter of credit or a guarantee. In the current case, Piedmont is automatically seeking credit for problems that may or may not develop in the future. Since customers are already held liable for all supplies of gas their marketer does not supply, I don't believe the customers should be required to pay higher gas costs to provide Piedmont with the extra credit assurances."

Mr. Yoho testified that Piedmont's CAA was "very quantitative and very consistent." Each month, if a TPA could not satisfy the creditworthiness requirements of Piedmont's CAA, then that TPA's customers would receive "a signal that a there was a credit issue." If the TPA was able to establish credit, but subsequently had a problem, both Piedmont and the TPA's customers would have some protection. With regard to the TPA that experienced a problem on Piedmont's system last December, Mr. Yoho testified that there were no problems in terms of intra-month imbalances or any other delivery issues from June to November and that problems developed "very quickly." The Commission notes that, using the NUI plan, if that marketer had passed the creditworthiness scrutiny in June, then it is possible that the customers would have gotten neither a warning nor any protection.

As to the cost, the Commission notes that NUI's creditworthiness requirements had the ability to require such mechanisms as letters of credit if NUI was dissatisfied with other indicators of creditworthiness. If a letter of credit would be prohibitively expensive under Piedmont's CAA as Mr. O'Donnell testified, then it would also be prohibitively expensive when called for under NUI's plan. The distinction that Mr. O'Donnell drew was that, under the NUI plan, if the TPA was deemed creditworthy by the company, it would not have to incur the cost.

No other parties presented evidence on this issue.

Based on the foregoing, the Commission concludes that Piedmont's proposed tariff revisions, including its TPA creditworthiness requirements, are designed to address a real threat to Piedmont and its customers, are reasonable in scope, and are neither unduly costly nor inconsistent with prior TPA creditworthiness mechanisms approved by the Commission.

The Commission interprets the language in Piedmont's CAA to mean that Piedmont will examine the creditworthiness of each TPA and will require appropriate credit, in form and substance acceptable to Piedmont, equivalent to the amount described in the CAA.

The CAA requires each TPA to "establish credit in the form of a Letter of Credit, escrow deposit, parental guaranty or otherwise, in form and substance acceptable to Piedmont." The Commission interprets "otherwise" to mean a reasonable mechanism satisfactory to Piedmont. Piedmont witness Yoho testified that a supplier guaranty could be another acceptable mechanism for establishing credit.

The Commission approves Piedmont's tariff with the understanding that the forms of credit mechanisms listed in the CAA are non-exclusive and will be applied to each marketer in a reasonable manner based on that marketer's situation.

The Commission notes that, the in the event a party considers the application of a specific creditworthiness mechanism by Piedmont to be unfair, that party has the option of filing a complaint before this Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence supporting this finding of fact is contained in the testimony of CUCA witness O'Donnell and Piedmont witness Yoho.

In his testimony, Mr. O'Donnell indicated that, in his view, Piedmont bears no third-party risk with respect to TPAs that do not take title to the gas delivered onto Piedmont's system for the benefit of their customers. In that testimony, Mr. O'Donnell further recommended that TPAs that do not take title to gas be exempted from the Company's proposed creditworthiness requirements. In his rebuttal testimony, Mr. Yoho took issue with Mr. O'Donnell's assertion and indicated that TPAs who do not take title to gas "have exactly the same operational profile on our system as third-party agents that do take title to gas." As a result, according to Mr. Yoho, both types of TPAs present the same risk profile.

No other party presented evidence on this issue.

The Commission concludes that it is unable to distinguish any variation in the risks to Piedmont and its customers presented by the activities of TPAs that take title to gas from those that do not take title to gas. As such, the Commission finds no basis to treat these two groups of TPAs differently for purposes of Piedmont's creditworthiness requirements.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence supporting this finding of fact is contained in the testimony of CUCA witness O'Donnell and Piedmont witness Yoho.

In his testimony, Mr. O'Donnell testified that customers of the "rogue marketer" described by Piedmont did not know the extent of the TPA's financial and operational difficulties and had they known the extent of the problems, they could have taken action before Piedmont did. Mr. O'Donnell proposed that Piedmont be required to disclose substantive information about a TPA's performance on the Piedmont system to each of its customers and to provide copies of all communications between Piedmont and a TPA to affected customers. Mr. O'Donnell stated that CUCA was drafting a template agency agreement that will require that all TPA's notify customers immediately of any notices sent by Piedmont to the TPA regarding the TPA's performance.

Mr. Yoho testified that many of the communications between Piedmont's gas control personnel and TPAs are verbal in nature and need to be because of the need to communicate and take immediate action. He asserted that it is not practical or even possible to provide a copy of verbal notices to customers. Mr. Yoho testified that TPAs consider much of the information about how they are setting up their pools to be proprietary. He added that nomination and burn information is considered proprietary by individual customers. Finally, Mr. Yoho testified that TPAs are retained by customers and Piedmont believed that the primary obligation to provide information about a TPA's conduct should be created between the TPA and the customer.

Piedmont witness Yoho stated that Piedmont has agreed to provide customers with copies of all formal notices issued to TPAs.

No other party presented evidence on this issue.

Based on the foregoing, the Commission concludes that it is not reasonable or practicable to require Piedmont to provide detailed aggregate information about TPA performance to its customers or to require Piedmont to provide copies of all communications between Piedmont and the TPA to its customers. The Commission does find it reasonable to require Piedmont to provide TPA customers with copies of all official notices issued to the TPA by Piedmont.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence supporting this finding of fact is contained in the testimony of CUCA witness O'Donnell and Piedmont witness Yoho.

In his testimony, Mr. O'Donnell proposed that Piedmont transportation customers be permitted to change TPAs on an intra-month basis if they terminate their relationship with a TPA for any reason. Mr. Yoho opposed this proposal on several grounds. First, according to Mr. Yoho, the administration of daily and monthly nominations and imbalance allocations for TPAs, who are acting as agents for multiple customers at any given time, is a substantial challenge. Allowing *ad hoc* intra-month changes of TPAs, whereby customers could move between multiple TPA pools within a single month, would exponentially complicate this task. Second, according to Mr. Yoho, Piedmont's existing systems are not capable of accommodating intra-month TPA changes as a routine matter. Piedmont did agree to allow a customer to designate a new TPA intra-month if the original TPA designated by that customer is suspended from operating on Piedmont's system.

No other party presented evidence on this issue.

Based on the foregoing, the Commission concludes that it is not reasonable to require Piedmont to accommodate intra-month changes in TPAs as a matter of course, but that it is reasonable for Piedmont to allow TPA changes where a customer's TPA is suspended from operating on the Piedmont system.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont's proposed TPA tariff modifications, as amended by its April 28, 2006 Reply Comments, are hereby approved to be effective on the first day of the month following the issuance of this order;

2. That the Company file revised tariff sheets consistent with this order within ten (10) days of the date hereof; and

3. That the jurisdiction of the Commission to hear and resolve complaints related to the application of the tariff provisions approved herein, or other provisions of Piedmont's tariffs, is preserved.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of October, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

wg101206.01

DOCKET NO. G-49, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by R.J. Griffin & Company for Approval	)	
of Natural Gas Metering Plan for a Condominium	)	ORDER APPROVING
Apartment Building at 230 South Tryon Street in	)	METERING PLAN
Charlotte, North Carolina	)	

BY THE COMMISSION: On April 7, 2006, R.J. Griffin & Company (Griffin) filed a letter requesting the Commission to find that the natural gas metering plan for a condominium apartment building at 230 South Tryon Street, Charlotte, North Carolina, meets the requirements of G.S. 143-151.42 and may be installed without approval of the Commission. Alternatively, Griffin requested the Commission to approve the installation of a natural gas meter that supplies gas for a "fresh air" unity that provides air to corridors, common areas, and community amenities, for heating the pool, and for gas grills.

Griffin is the general contractor for the construction of 107 condominium apartments, including eight "penthouses." All condominium apartments will have electric water heaters and electric heating and cooling. All penthouse apartments will have natural gas for kitchen cooking, patio grilling, and fireplace heating. All condominium apartments will have separate electric meters, and all penthouse apartments will have separate gas meters. The building will have community amenities, including a concierge, doorman, lobby, fitness center, pool, and a leisure activity salon for its residents.

According to Griffin, an AAON "fresh-air unit" will deliver fresh, temperature-neutral (between 70 and 74 degrees) and low-humidity air to the core of the building for heating and cooling the corridors, common areas and community amenities (lobby, salon, fitness center, etc.). The AAON unit will use electrical cooling components for cooling air and gas components for heating air to ensure that the air supplied to the building is temperature-neutral. The AAON unit is equipped with an "economizer" feature that is designed to prevent unnecessary operation of the heating or cooling functions when the outside air conditions meet the temperature and humidity requirements of the unit. Griffin intends to install gas-operated grills on the exterior patios of the non-penthouse condominium apartments and a gas-operated heater for heating the water in the building's pool. Griffin proposes that the gas for these uses be metered through the same meter used for the natural gas connection to the fresh-air AAON unit. Bills for the natural gas usage monitored by this natural gas meter will be paid by the condominium owners' association. Water used in the common areas of the building will be electrically heated and metered by a common area meter.

Griffin asserts that, because each condominium apartment's electric temperature control system is individually metered, and each penthouse apartment has an individual gas meter, the condominium apartment owner is responsible for his or her individual energy use. This feature of the 230 South Tryon building is consistent with the premise of G.S. 143-151.42. Unlike the discretionary interior use of electricity and gas for heating and cooling, lighting, and operating electrical appliances (*e.g.*, televisions), individuals will only use the gas needed for grilling, regardless of whether grill gas is connected to a common meter. Even with the addition of the patio grills to the meter for the corridors, common areas, and community amenities, the energy used by gas grills will be minuscule compared to the other energy uses in the building — all of which are individually metered. Furthermore, the design of this building makes it physically impossible to accommodate separate metering solely for gas grills.

The Public Staff presented this matter at the April 24, 2006, Commission Conference. The Public Staff stated that it had reviewed the proposed master metering plan and determined that it provides energy savings and effects individual accountability in keeping with the purpose of G.S. 143-151.42. The Public Staff stated that, except for the gas grills, the plan does not involve residential gas service through a master meter, and it appears doubtful that the grills would be offered apart from the gas that serves the community areas of the building. Thus, as Griffin noted, the plan goes further than the system that was approved in Docket No. G-45, Sub 0, with respect to The Metropolitan Condominiums in downtown Raleigh proposed by the Florian Companies.

Based on the foregoing, and the recommendation of the Public Staff, the Commission concludes that Griffin's request for use of a natural gas master meter for the fresh air unit, pool heating, and gas grills as proposed for 230 South Tryon in Charlotte should be approved.

IT IS, THEREFORE, SO ORDERED.
This the 10th day of May, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah042406.01
Commissioner Ervin dissents

DOCKET NO. G-49, SUB 0

Commissioner Sam J. Ervin, IV, dissenting.

Although I agree that the manner in which Griffin proposes to heat and cool the building corridors, common areas, community amenities, and common area water supply and to heat the pool planned for the proposed condominium building at 203 South Tryon Street in Charlotte, North Carolina, does not run afoul of G.S. 143-151.42, I cannot concur in the majority's decision to reach the same conclusion with respect to the gas grills to be installed on the exterior patios of the "non-penthouse" units. As a result, while the proposed condominium structure will undoubtedly provide benefits to its residents and the downtown Charlotte community, I respectfully dissent from the Commission's conclusion that the failure to individually meter the natural gas used to operate these gas grills is not inconsistent with North Carolina's master metering statute.

The Supreme Court of North Carolina has clearly stated that the Commission has no authority except that granted by the General Assembly. State ex rel. Utilities Commission v. National

Merchandising Corporation, 288 N.C. 715, 722, 220 S.E. 2d 304 (1975); State ex rel. Utilities Commission v. General Telephone Company of the Southeast, 281 N.C. 318, 336, 189 S.E. 2d 705 (1972). For that reason, "the Commission has no authority to permit that which is forbidden by statute . . . ." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 464, 232 S.E. 2d 184 (1977). "When the language of a statute is clear and unambiguous, it must be given effect and its clear meaning may not be evaded by an administrative body or court under the guise of construction." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 465, 232 S.E. 2d 184 (1977). See also: Peele v. Finch, 284 N.C. 375, 200 S.E. 2d 663 (1969); State ex rel. Utilities Commission v. Lumbee River Electric Membership Corporation, 275 N.C. 260, 166 S.E. 2d 663 (1969). As a result, the issues raised by Griffin's request for a declaratory ruling can only be resolved by comparing the facts as alleged in Griffin's April 7, 2006, filing with the language of G.S. 143-151.42.

G.S. 143-151.42 provides that "it shall be unlawful for any new residential building ... to be served by a master meter for electric service or natural gas service" and that "[e]ach individual dwelling unit shall have individual electric service and, if it has natural gas, individual natural gas service with a separate natural gas meter, which service and meter shall be in the name of the tenant or other occupant of said apartment or dwelling unit." The General Assembly undoubtedly enacted G.S. 143-151.42 in order to encourage the conservation of electricity and natural gas by ensuring that building residents pay for the energy that they elect to consume. The only potentially relevant exception to the prohibition against master metering contained in G.S. 143-151.42 allows master meeting by "any owner or builder of a multi-unit residential building who desires to provide central heat or air conditioning or central hot water from a central furnace, air conditioner or hot water heater which incorporates solar assistance or other designs which accomplish greater energy conservation than separate heat, hot water, or air conditioning for each dwelling unit." Provisions creating exceptions to the general prohibition against master metering for technical infeasibility or de minimis use are conspicuously absent from G.S. 143-151.42.

According to Griffin's April 7, 2006, filing, each of the 107 units in the proposed condominium building will be "electrically heated and cooled and have individual electric water heaters." In addition, eight "penthouse" apartments "will have gas for range cooking, outdoor grilling and fireplace use." The electricity and natural gas used to operate these appliances will be separately metered, rendering this usage fully compliant with the provisions of G.S. 143-151.42. In addition, Griffin indicates that "[h]eating and cooling in the building's corridors, common areas and community amenities (i.e., lobby, salon, fitness center, etc.) will be accomplished" using a "fresh air" unit that incorporates "electrical cooling components to cool air and gas components to heat air" and that utilizes an "economizer" feature to "prevent[] unnecessary operation of the heating or cooling functions." The electricity and natural gas necessary to operate the "fresh air" unit, the electricity needed to heat water used in the common areas, the natural gas used to heat the building's pool, and the natural gas used to heat gas grills located on the patios exterior to the "non-penthouse" apartments will all be metered through common electric and natural gas meters, with "[b]ills for natural gas usage monitored by this proposed natural gas meter [to be] paid by the condominium owners' association, which derives its funds from assessments of the residents of the building."

In approving Griffin's request, the majority appears to accept the Public Staff's determination that the plan proposed by Griffin "provides energy savings and effects individual accountability in keeping with the purpose of G.S. 143-151.42"; that, "except for the gas grills," the building plan "does not involve residential gas service [provided] through a master meter"; and that "it appears doubtful that the grills would be offered apart from the gas that serves the community areas of the building." Except for these statements, the Commission does not provide any justification for its conclusion "that Griffin's request for use of a natural gas master meter for the fresh air unit, pool heating, and gas grills proposed for 230 South Tryon in Charlotte should be approved."

I fully agree with the Commission's conclusion that master metering the natural gas and electricity used in connection with heating and cooling the corridors, common areas, community amenities, and common area water supply and heating the pool is permissible under G.S. 143-151.42. The relevant statutory language, which requires the provision of "individual electric service and, if it has natural gas, individual natural gas service," clearly indicates that the prohibition against master metering is specifically directed to service provided in individual residential units rather than to service provided on a common basis to all residents of or to other uses occurring in the building in question. Such an interpretation of G.S. 143-151.42 is consistent with its obvious purpose of fostering energy conservation by ensuring that the occupants of covered multi-tenant buildings pay for the electric and natural gas consumption over which they have direct and immediate control. As a result of the fact that no single unit occupant will have the ability to determine the amount of electric or natural gas usage associated with heating and cooling the corridors, common areas, community amenities, and common area water supply and heating the swimming pool, I concur with the majority's conclusion that master metering the electricity and gas used for these purposes does not contravene G.S. 143-151.42.

I am unable, however, to reach the same conclusion with respect to the usage associated with the gas grills to be located on the exterior patios of the "non-penthouse" units. Unlike the electricity and natural gas used to heat and cool the corridors, common areas, community amenities, and common area water supply and the natural gas used to heat the pool, the gas used in these grills is unquestionably part of the natural gas service provided to individual residential units. Since the amount of natural gas used in connection with the operation of these grills is completely within the control of the unit occupant, this usage is squarely within the general scope of the prohibition against master metering contained in G.S. 143-151.42. The fact that "it appears doubtful that the grills would be offered apart from the gas that serves the community areas of the building" does not suffice to justify the result reached by the Commission in this proceeding given that the statute totally lacks any sort of "technical feasibility" exception. Similarly, to the extent that the Commission's conclusion that the building design "provides energy savings and effects individual accountability" is relevant to an analysis of the "gas grills" issue, it fails to justify the result reached by the majority given that the "energy savings" exception to the G.S. 142-151.42 requires "greater energy conservation than separate heat, hot water, or air conditioning for each dwelling unit" and the fact that the record is devoid of any evidence tending to show that greater energy savings should result from the proposed design than would result from individually metered gas service to the gas grills. As a result, neither of the arguments apparently adopted by the Commission in order to approve the provision of natural gas service to the gas grills located on the exterior patios of the "non-penthouse" units can be squared with the language of G.S. 143-151.42.[1]

In addition to the arguments apparently accepted by the majority, Griffin also argues that the fact that "each 'individual dwelling unit' [will] have an individual meter for electricity and gas used in the unit" suffices to meet the requirements of G.S. 143-151.42 and that "the energy used by the gas grills at 230 South Tryon will be miniscule compared to the other energy uses in the building—all of which [will be] individually metered." I do not, unfortunately, find either of these additional

[1] I recognize that the Commission adopted similar reasoning in In re Harrington Street Associates, Order Approving Master Metering, Docket No. G-47, Sub 0 (2004). As the Commission's records reflect, I did not participate in that decision.

arguments persuasive. Acceptance of the first of these arguments, which amounts to an assertion that the statute does not require that all of the electric or natural gas service provided to a particular dwelling unit be individually metered as long as some or most of it is metered in that fashion, finds no support in the language of G.S. 143-151.42. Allowing some, but not all, of the electric and natural gas service to a particular building unit to be master metered would eviscerate the clear statutory requirement that "[e]ach individual dwelling unit shall have individual electric service and, if it has natural gas, individual natural gas service with a separate natural gas meter." Similarly, even if G.S. 143-151.42 incorporates a de minimis exception, there is nothing in the present record beyond the conclusory assertions of Griffin and the Public Staff to the effect that "the energy used by these gas grills will be miniscule compared to the other energy uses in the building" that establishes that the usage in question will be de minimis. Any de minimis exception to the prohibition against master metering contained in G.S. 143-151.42 should rest on some quantification of the relevant energy use and should be predicated on a showing other than a simple comparison of the consumption of the appliance in question with the total consumption associated with occupancy of the building. As a result, I do not find either of these additional arguments persuasive.

I fully understand and sympathize with the majority's reluctance to disapprove an attractive feature of an overall development plan on the basis of the provisions of a statute that antedates many modern building design features. I have no doubt that the condominium building at 230 South Tryon will provide a source of high quality housing in central Charlotte. Unfortunately, however, I simply do not believe that these benefits permit us to approve facilities that appear inconsistent with the provisions of G.S. 143-151.42. As I stated in my dissent from the Commission's decision in In re Florian Companies, Docket No. G-45, Sub 0, Ninety-First Report of the North Carolina Utilities Commission: Order and Decisions 418, 423 (2001), "[t]he General Assembly has defined the circumstances under which master metering is and is not permissible" and the "only avenue available ... for seeking relief from the provisions of G.S. 143-151.42 runs through the General Assembly rather that the Commission." As a result, I respectfully dissent from the Commission's conclusion that the gas grills proposed to be installed on the exterior patios of the "non-penthouse" units at 230 South Tryon are not inconsistent with G.S. 143-151.43.

\s\ Sam J. Ervin, IV
Commissioner Sam J. Ervin, IV

DOCKET NO. G-5, SUB 481

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

HEARD IN: Statesville Hall of Justice Annex, Statesville, North Carolina, on July 12, 2006; Buncombe County Courthouse, Asheville, North Carolina, on July 12, 2006; Gastonia Police Department, Gastonia, North Carolina, on July 13, 2006; Durham City Hall, Durham, North Carolina, on July 13, 2006; and the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina, on August 21, 2006, and August 22, 2006

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

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

B. Craig Collins, SCANA Corporation, 1426 Main Street, Columbia, South Carolina 29218

Mary Lynne Grigg, Womble Carlyle Sandridge & Rice, PLLC, Post Office Box 831, Raleigh, North Carolina 27602

William R. Pittman, The Pittman Law Firm, PLLC, 1312 Annapolis Drive, Suite 200, Raleigh, North Carolina 27608

For the Using and Consuming Public:

Elizabeth D. Szafran and Ralph J. Daigneault, Staff Attorneys, 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.:

James P. West, West Law Offices, PC, Suite 2325, Two Hannover Square, 434 Fayetteville Street, Raleigh, North Carolina 27601

BY THE COMMISSION: On March 1, 2006, 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 22, 2006, Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene, which the Commission granted on March 29, 2006.

On April 3, 2006, 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, John J. Spanos, Sharon D. Boone, and Candace A. Paton.

On April 27, 2006, the Attorney General of North Carolina (Attorney General) filed his notice of intervention.

By Order issued May 4, 2006, 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 3, 2006. 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 5, 2006, the Commission filed an errata order to correct a clerical error.

On May 26, 2006, PSNC filed an amendment to its Application providing additional NCUC Form G-1 data.

On June 14, 2006, 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 June 20, 2006, the Commission issued an order granting PSNC's motion. On July 19, 2006, the Company filed a Pro Hac Vice registration statement as it had been provided to the Administrative Office of the Courts.

On July 12, 2006, a hearing on the Application was held in Statesville as scheduled. At the hearing in Statesville, no person testified as a public witness. On July 12, 2006, a hearing was held in Asheville as scheduled. At the hearing in Asheville, Keith Levi testified as a public witness. On July 13, 2006, a hearing was held in Gastonia as scheduled. At the hearing in Gastonia, William L. Martin and Elizabeth Glenn testified as public witnesses. On July 13, 2006, a hearing was held in Durham as scheduled. At the hearing in Durham, no person testified as a public witness.

On July 31, 2006, the Company filed its Motion for Extension of Time to File Intervenor and Rebuttal Testimony. By Order, the Commission granted the motion on August 1, 2006.

On August 8, 2006, the Company filed its Motion for Extension of Time to File Intervenor Testimony. By Order, the Commission granted the motion on August 9, 2006.

On August 10, 2006, the Attorney General filed the direct testimony and exhibits of Roger D. Colton.

On August 16, 2006, the Company, the Public Staff, and CUCA (Stipulating Parties) filed a joint stipulation and exhibits (Stipulation) resolving all issues in this proceeding as among the

Stipulating Parties. On August 17, 2006, the Company filed the supplemental testimony of Candace A. Paton in support of the Stipulation.

On August 17, 2006, the Attorney General filed a letter requesting that the Commission allow the admission into evidence of the testimony of Roger D. Colton without the need for him to appear at hearing. The Attorney General further stated that he did not object to the Stipulation.

On August 21, 2006, a hearing was held in Raleigh as scheduled. At the hearing in Raleigh, Loraine Poacher, JoAnne Forgach, and William Carson testified as public witnesses.

On August 22, 2006, the hearing in Raleigh was continued as scheduled and 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, John J. Spanos, Sharon D. Boone, and Candace A. Paton. The prefiled direct testimony of Attorney General witness Roger D. Colton also was offered and accepted into evidence. Company witness Paton testified at the hearing and answered questions from the Commission and the Public Staff.

On August 25, 2006, the Company filed Supplemental Paton Exhibit 2 to Company witness Paton's supplemental testimony per the Commission's request at the evidentiary hearing.

On September 25, 2006 PSNC, the Public Staff, and CUCA filed a Joint Proposed Order.

On October 18, 2006, PSNC filed a letter with a proposed Customer Notice Bill Insert.

Based on the verified Application, testimony, and exhibits received into evidence at the hearings, 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 within a franchised area consisting of all or parts of twenty-eight (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 the Application in this docket, the Company sought: (i) an increase of $28,422,375 in revenue, offset by a decrease of $7,520,155 related to a reduction in the fixed-cost portion of the Company's cost of gas, resulting in an overall increase of $20,902,220 in the Company's rates and charges for natural gas utility service; (ii) certain changes to the cost allocations and rate design underlying existing rates for the Company; (iii) revisions to the current tariff language and Rules and Regulations; (iv) amortization of certain deferred account balances; (v) depreciation rates for plant

maintained by the Company; and (vi) the implementation of customer conservation and assistance initiatives.

5. The Company is properly before the Commission with respect to the relief sought in the Application pursuant to the provisions of Chapter 62 of the General Statutes.

6. The appropriate test period for use in this proceeding is the twelve-month period ended December 31, 2005, updated for certain known and measurable changes through June 30, 2006.

7. The Stipulation executed by PSNC, the Public Staff, and CUCA is not opposed by the Attorney General, the only other party to the proceeding, and it settles all matters in this docket.

8. The Stipulation provided for an increase in annual revenues for the Company of $15,188,102, offset by $9,220,399 of reductions in fixed gas costs, for a net increase in rates and charges of $5,967,703.

9. The 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 which has been consumed by depreciation expense, all as described and set forth in Paragraph 4 and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, is appropriate for use in this docket.

10. The Company's end-of-period pro forma revenues under the present and proposed rates, as set forth in Paragraph 6.A and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, are reasonable for use in this docket.

11. The Company's operating expenses, including actual investment currently consumed through reasonable actual depreciation, as set forth in Paragraph 6.A and Exhibit A of the Stipulation and reflected on Schedule 1 hereto, are reasonable for use in this docket.

12. 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 ascertained pursuant to Paragraph 9 above, is set forth in Paragraph 6.B and Exhibit A of the Stipulation and is reflected on Schedule 1 hereto. The Commission makes no determination with respect to PSNC's authorized rate of return on common equity in this proceeding. Thus, PSNC has no Commission-authorized rate of return on common equity as of the date of this Order.

13. For the purpose of this proceeding, the appropriate level of adjusted sales and transportation volumes is 723,500,040 therms, which is comprised of 416,357,726 therms of sales quantities and 307,142,314 therms of transportation quantities. The appropriate level of company use gas is 732,710 therms and of lost and unaccounted for gas is 7,235,000 therms, and the appropriate level of purchased gas supply is 424,325,436 therms, consisting of sales volumes, company use and lost and unaccounted for gas.

14. The fixed gas costs that should be embedded in the proposed rates and used in true-ups 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 D to the Stipulation.

15. The appropriate depreciation rates for use in this proceeding are those set forth in the depreciation study filed by the Company in this proceeding, as described and set forth in Paragraph 5 and Exhibit B of the Stipulation.

16. The rate design and rates, including volumetric rates, fixed monthly charges, and other charges, as described in Paragraph 7 of the Stipulation and reflected in Exhibits C and F 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.

17. The proposals to remove the commodity cost bifurcation for Rate Schedules 145 and 150 customers, as described in Paragraph 12 and Exhibit F of the Stipulation, and to implement the annual election requirement for customers on Rate Schedules 145, 150, 175, and 180 are reasonable and should be approved.

18. The reasonable end of period level for the total cost of gas in this proceeding is $410,466,808, and the reasonable pro forma level after the rate increase is $394,840,028, as described in Paragraph 11 and Exhibit H to the Stipulation and reflected on Schedule 1 hereto.

19. The proposed temporary rate decrements described in Paragraph 11.F of the Stipulation are fair and reasonable and should be approved for implementation for a twelve-month period beginning on the effective date of rates hereunder.

20. The proposed "R_i" values, heat-sensitive factors, and base load factors to be used in the Company's Weather Normalization Adjustment (WNA) mechanism as set forth in Paragraph 9 and Exhibit E of the Stipulation are fair and reasonable and should be approved.

21. The proposal to record all negotiated losses in the All Customers Deferred Account upon the effective date of rates hereunder, as described in Paragraph 11.E of the Stipulation, is fair and reasonable and should be approved.

22. The proposal to capitalize PSNC's electric power costs associated with operating its liquefied natural gas (LNG) facility as part of LNG inventory and to roll these power costs into the average cost of LNG so that the higher level of costs flows through the commodity cost of gas, subject to true-up, as discussed in Paragraph 11.D of the Stipulation, is just and reasonable and should be approved.

23. The proposed treatment of the gas cost portion of uncollectibles expense, as set forth in Paragraph 14 of the Stipulation, is fair and reasonable and should be approved.

24. The appropriate Allowance for Funds Used During Construction (AFUDC) rate for the Company should be the overall rate of return.

25. The proposed amortization of certain deferred costs, as set forth in and described in Paragraph 13 of the Stipulation, is fair and reasonable and should be approved.

26. The tariffs attached to the Stipulation as Exhibit F are fair and reasonable and should be approved.

27. The service regulations reflected in Exhibit G to the Stipulation are fair and reasonable and should be approved.

28. All of the provisions of the Stipulation are fair and reasonable and should be approved.

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, the provisions of Chapter 62 of the General Statutes, and the Commission's records as a whole. These findings are primarily jurisdictional 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 twelve-months ended December 31, 2005. In its Order of May 4, 2006, the Commission ordered the parties to use a test period consisting of the twelve-months ended December 31, 2005, 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, 2006. These adjustments were not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

This finding is supported by the Stipulation, the supplemental testimony of Candace A. Paton, and the August 17, 2006 letter filed by the Attorney General.

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 issues in the proceeding. In his August 17, 2006 letter, the Attorney General indicated that he had no objection to the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

These findings are supported by the Application, the direct testimony of Company witness Boone, the supplemental testimony of Company witness Paton, the Stipulation, and the testimony of Company witness Paton at the hearing.

Boone Exhibit 6 indicates that the Company filed for a revenue increase of $28,422,375, offset by a decrease in fixed gas costs of $7,520,155, for a net increase of $20,902,220. The Stipulation in Paragraph 6.B indicates that the Company should be allowed to increase its annual level of margin through the rates and charges approved in this case by $15,188,102, offset by $9,220,399 of reductions in fixed gas costs, for a net annual increase in rates and charges of $5,967,703. Company witness Paton testified at the hearing that, as part of the negotiations with the Stipulating Parties, the Company agreed to withdraw its proposal to include in the cost of service an amount to implement customer conservation and assistance initiatives. She further testified that the Company would continue its customer education efforts without seeking to recover the costs through rates. These findings are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

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 that has been consumed by depreciation expense, is described and set forth in Paragraph 4 and Exhibit A to the Stipulation and reflected in Schedule 1 hereto.

The amounts shown 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 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 reviewed these amounts, as well as all of 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. 10

The end of test period pro forma revenues under the Company's present and stipulated proposed rates are set forth in Paragraph 6.A and Exhibit A to the Stipulation and reflected on Schedule I hereto.

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 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. 11

The Company's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, are set forth in Paragraph 6.A and Exhibit A to the Stipulation and reflected on Schedule 1 hereto.

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 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. 12

The overall rate of return on the cost of the Company's used and useful property is set forth in Paragraph 6.B and Exhibit A to the Stipulation and reflected on Schedule 1 hereto. This overall rate of return is the result of negotiations among the Stipulating Parties, as described in the Stipulation and the supplemental testimony of Company witness Paton, and it is not contested by any party. The

Commission has reviewed the stipulated overall rate of return and the evidence of record relating to rate of return and concludes that the stipulated overall rate of return is fair and reasonable.

The Commission also concludes that the stipulated overall rate of 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 which are fair to its customers and to its existing investors.

The Commission makes no determination with respect to PSNC's authorized rate of return on common equity in this proceeding. Thus, PSNC has no Commission-authorized rate of return on common equity in this proceeding. This is similar to the approach taken by the Commission in its Order Approving Stipulation in the Dominion North Carolina Power investigation of rates and charges in Docket No. E-22, Sub 412, and in its Order Approving Partial Rate Increase and Requiring Conservation Initiative in the Piedmont Natural Gas Company, Inc., general rate case in Docket No. G-9, Sub 499.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The level of adjusted sales and transportation volumes used in the Stipulation is 723,500,040 therms and the level of purchased gas supply as shown on Exhibit H to the Stipulation is 424,325,436 therms. The throughput volume level is derived as follows:

Sales	416,357,726
Transportation	307,142,314
Total Throughput	723,500,040

The level of purchased gas supply is 424,325,436 therms, derived as follows:

Sales	416,357,726
Company Use	732,710
Lost & Unaccounted for	7,235,000
Total Gas Supply	424,325,436

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 the supplemental testimony of Company witness Paton, and are not opposed by any party. The Commission has reviewed this throughput level and concludes that it is a fair and reasonable approximation of the Company's pro forma adjusted sales and transportation volumes. The Commission has also reviewed the purchased gas supply level and concludes that it is a fair and reasonable approximation of the Company's pro forma purchased gas supply level.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

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 D to the Stipulation:

Rate Schedule	Description	Fixed Gas Cost Rate ($/therm)	Fixed Gas Cost Apportionment %
105	Residential Value	$0.13879	45.0114%
110	Residential Standard	$0.14992	16.6531%
125/126	Small General Service	$0.12092	26.9257%
145	Large General Service	$0.05800	3.0864%
150	Interruptible Commercial and Industrial	$0.03601	0.8491%
175	Large General Service Transportation	$0.02267	2.5415%
180	Interruptible Commercial and Industrial Transportation	$0.01604	4.9328%

No party has contested this proposal. The Commission has examined these amounts, as well as all record evidence on fixed gas cost allocations, and concludes that the stipulated allocations of fixed gas costs are fair and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

In Paragraph 5 of the Stipulation, the Stipulating Parties proposed to utilize the depreciation rates contained in the depreciation study filed by the Company with its Application and supported by the direct testimony of Company witness Spanos, as reflected on Exhibit B to the Stipulation. No party contested this proposal. The Commission has reviewed this proposal and concludes that use of the Company's filed depreciation rates, as reflected on Exhibit B to the Stipulation, is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding is contained in the Application, in Paragraph 7 of the Stipulation and Exhibits C and F thereto, in the direct and supplemental testimony of Company witness Paton, and in the direct testimony of Attorney General witness Colton.

The computation of revenues under the proposed rates (based on a Benchmark Commodity Cost of Gas of $0.825 per therm) is set forth on Exhibit C 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 to increase monthly facilities charges for residential customers from existing levels of $7.74 and $10.65 for Rate Schedules 105 and 110, respectively, to $15.00 per month. According to Company witness Paton the intent of the proposed increase was to implement a rate structure that recognizes that many of an LDC's costs are fixed and are not dependent on the quantity of gas consumed. Company witness Paton stated that recovery of more fixed costs in the monthly facilities charges would minimize the variance in customer bills on a monthly basis and improve margin stability for the Company. In his direct testimony, Attorney General witness Colton opposed this proposal, stating that increased fixed monthly charges for residential customers, as proposed by the Company, have a disproportionate impact on lower income customers. In the Stipulation and as reflected in the supplemental testimony of Company witness

Paton, the Stipulating Parties agreed to a monthly facilities charge for all residential customers of $10.00 per month, 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 C to the Stipulation are somewhat different than those originally proposed by the Company, but that they 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 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 12 and Exhibit F of the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulating Parties agreed that, effective November 1, 2006, the Monthly Commodity Gas Cost component of the rates paid by Rate Schedules 145 and 150 customers will be discontinued and replaced with the Benchmark Commodity Cost of Gas applicable to Rate Schedules 105, 110, 115, 125, and 126 in effect on that date. Effective November 1, 2006, the rates for all sales customers, including Rate Schedule 145 and 150 customers, will include the Benchmark Commodity Cost of Gas approved by the Commission. Pursuant to the Commission's order in Docket No. G-5, Sub 379, the current sales rate for Rate Schedule 145 is composed of the Rate Schedule 175 transportation rate plus an element for the Monthly Commodity Gas Cost determined pursuant to the Company's PGA Procedures – Rider D. Similarly, the current sales rate for Rate Schedule 150 is composed of the Rate Schedule 180 transportation rate plus the Monthly Commodity Gas Cost. Temporary rate increments or decrements related to the Sales Customers Only Deferred Account currently do not apply to Rate Schedule 145 or 150 customers. The existing Monthly Commodity Gas Cost component of the rates paid by Rate Schedule 145 and 150 customers is a market-based rate determined in the manner specified in Section I of Rider D.

The Stipulating Parties also agreed that the ability of customers on Rate Schedules 145, 150, 175, and 180 to switch between sales and transportation service on a monthly basis will be replaced with an annual election process whereby such customers must commit to either sales (Rate Schedules 145 or 150) or transportation (Rate Schedules 175 or 180) service.

No party contested these proposals. The Commission has reviewed these proposals and concludes that the Company's elimination of commodity cost bifurcation is appropriate and that the implementation of the annual election requirement for customers on Rate Schedules 145, 150, 175, and 180, as detailed in Exhibit F of the Stipulation, is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding is contained in Paragraphs 11.B and 11.C of the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulating Parties support the pro forma level of the total cost of gas after the rate increase as described in Paragraph 11.C of the Stipulation. No party has contested this assertion. The Commission has examined these amounts as set forth in Paragraphs 11.B and 11.C of the Stipulation, finds them to be fair 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 Paragraph 11.F of the Stipulation and the supplemental testimony of Company witness Paton.

The Stipulating Parties agreed to the following proposed temporary rate decrements effective for the period November 1, 2006, through October 31, 2007, to refund the balance in the All Customers Deferred Account:

Rate Schedule 105 - \$.022248 per therm;
Rate Schedule 110 - \$.025347 per therm;
Rate Schedules 125 and 126 - \$.019396 per therm;
Rate Schedules 145 and 175 - \$.013196 per therm; and
Rate Schedules 150 and 180 - \$.007458 per therm.

The Commission has reviewed the proposed 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 testimony of Company witness Paton, Paragraph 9 and Exhibit E of the Stipulation, and the supplemental testimony of Company witness Paton.

The Stipulating Parties agreed to the appropriate WNA factors, which were not opposed by any parties. The Commission has considered the WNA "R_i" values, heat-sensitive factors, and base load factors set forth in Paragraph 9 of the Stipulation and Exhibit E thereto and concludes that they are fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding is found in Paragraph 11.E of the Stipulation.

The Stipulating Parties agreed to the proposal to record all negotiated losses in the All Customers Deferred Account upon the effective date of rates hereunder, as described in Paragraph 11.E of the Stipulation. No party opposed this proposal.

The Commission has reviewed this proposal and concludes that the proposed treatment of recording all negotiated losses in the All Customers Deferred Account is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

In Paragraph 11.D of the Stipulation, the Stipulating Parties agreed that the electric power costs associated with operating the Company's LNG facility should no longer be recorded as an operating and maintenance expense, but, instead, should be capitalized as part of LNG inventory. The Stipulating Parties agreed that these power costs should be rolled into the average cost of LNG and that this higher level of cost should flow through the commodity cost of gas, subject to true-up.

This proposal to capitalize PSNC's electric power costs associated with operating its LNG facility as set forth in Paragraph 11.D of the Stipulation is not opposed by any party. The Commission has considered the proposal and finds that the treatment of these electric power costs is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence for this finding is contained in the direct testimony of Company witnesses Paton and Boone and in Paragraph 14 of the Stipulation.

In Paragraph 14 of the Stipulation, the Stipulating Parties agreed to adopt the Company's proposal to remove the gas portion of uncollectibles expense, net of write-offs (uncollectible write-offs minus recoveries) from base rates and recover these costs through the gas cost deferred accounts. The Stipulating Parties further agreed that the Company should record this entry in the Sales Customers Only Deferred Account for all such amounts. No party opposed this proposal.

The Commission has reviewed this proposal and concludes that the stipulated treatment of uncollectibles expense is fair and reasonable and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

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, 2006, should be the agreed upon overall rate of return. No party objected to this proposal.

The Commission has reviewed this proposal and concludes that the agreed upon AFUDC rate is fair and reasonable and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

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.

In Paragraph 13 of the Stipulation, the Stipulating Parties proposed certain agreed upon amortization periods for the treatment of the following deferred costs as of June 30, 2006: (a) manufactured gas plant costs; (b) pipeline integrity management costs; (c) workers compensation losses; and (d) excess deferred income taxes (EDIT). 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 and necessary for compliance with current federal regulations, pending the establishment of an appropriate recovery mechanism in a future proceeding.

The Stipulating Parties also agreed that it is appropriate to discontinue the decrement and special EDIT accounting procedures previously approved by the Commission in Docket Nos. G-5, Subs 280, 289, and 295. The Stipulating Parties agreed that the estimated November 1, 2006 balance of previously amortized plant-related EDIT and the balance of non-plant-related EDIT should be flowed back to customers over five years. In addition, the Stipulating Parties agreed that PSNC's income tax expense will now reflect a reduction for the annual amount of plant-related net EDIT amortized for book accounting purposes and the annual amortization of the balance on non-plant related EDIT based on a five-year amortization period.

No party opposed the proposals contained in Paragraph 13 of the Stipulation. The Commission has considered the proposed amortization periods and related matters set forth in Paragraph 13, as well as the relevant evidence in the record, and concludes that the stipulated amortization periods are fair and reasonable and should be approved. The Commission further concludes that the proposed continuation of regulatory asset treatment for pipeline integrity management costs is fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26 AND 27

The evidence supporting these findings is contained in the direct and supplemental testimony of Company witness Paton, the Stipulation, and Exhibits F and G thereto.

Company witness Paton testified to the proposed additional changes to the Company's tariffs and service regulations and the reasons underlying those changes. In general, she testified 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 service regulations which were agreed to among the Stipulating Parties, including those designed to address certain concerns raised by the Attorney General, are reflected in Exhibits F and G to the Stipulation. No party objected to these changes. The Commission has reviewed these changes to the Company's tariffs and service regulations and concludes that they are fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

For the reasons set forth in the foregoing paragraphs, the Commission concludes that the Stipulation in this proceeding 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 for all customer classes. The Commission finds and concludes that all of the provisions of the Stipulation, taken together, are fair and reasonable under the circumstances of this proceeding and should be approved.

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, 2006;

2. That PSNC is authorized to implement the tariffs attached to the Stipulation as Exhibit F effective November 1, 2006;

3. That PSNC is authorized to implement the service regulations attached as Exhibit G to the Stipulation effective November 1, 2006;

4. That PSNC shall file tariff and service regulations to comply with this Order within ten (10) days from the date of this Order;

5. That PSNC is authorized to implement the other actions, practices, principles, and methods agreed upon in the Stipulation and not inconsistent with this order; and

6. That PSNC shall give notice to its customers by means of a bill insert, beginning with the billing cycle that includes the rate changes approved herein, in the format submitted to the Commission with PSNC's October 18, 2006 letter.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of October, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

wr102306.01

Schedule

Public Service Company of North Carolina
Docket No. G-5, Sub 481
STATEMENT OF NET OPERATING INCOME FOR RETURN, RATE BASE AND OVERALL RETURN
For The Test Year Ended December 31, 2005

Line No.	Item	Per Company (a)	Adjustments (b)	After Adjustments (c)	Gas Cost Impact of Rate Shifting (d)	Rate Increase (e)	After Rate Increase (f)
1	NET OPERATING INCOME FOR RETURN						
2	Operating Revenues:						
3	Sales and transportation of gas	$572,133,650	$29,364,579	$601,498,229	($15,626,780)	$5,381,815	$591,253,264
4	Other operating revenues	2,838,848	122,358	2,961,206		585,888	3,547,094
5	Operating revenues, excl special contrac	574,972,498	29,486,937	604,459,435	(15,626,780)	5,967,703	594,800,358
6	Special Contract Revenues	375,447	-	375,447	-		375,447
7	Total operating revenues	575,347,945	29,486,937	604,834,882	(15,626,780)	5,967,703	595,175,805
8	Operating Expenses:						
9	Cost of gas	394,816,511	16,650,297	410,466,808	(15,626,780)		394,840,028
10	Operating and maintenance	83,999,800	(4,232,339)	79,767,461		38,156	79,805,617
11	Depreciation	33,733,193	2,409,339	36,142,532		-	36,142,532
12	General taxes	8,444,185	(8,698)	8,435,487			8,435,487
13	State income tax (6.9%)	2,414,168	964,128	3,378,296		409,139	3,787,435
14	Federal income tax (35%)	11,400,821	3,916,690	15,317,511		1,932,143	17,249,654
15	Amortization of investment tax credits	(237,551)	-	(237,551)			(237,551)
16	Total operating expenses	534,571,127	18,699,417	553,270,544	(15,626,780)	2,379,438	540,023,202
17	Net operating income for return	$40,776,818	$10,787,520	$51,564,338	$0	$3,588,265	$55,152,603
18	RATE BASE						
19	Plant in service	$1,021,096,991	$11,038,824	$1,032,135,815			$1,032,135,815
20	Accumulated depreciation	(389,041,905)	2,673,538	(386,368,367)			(386,368,367)
21	Net plant in service	632,055,086	13,712,362	645,767,448	0	0	645,767,448
22	Gas in Storage	66,236,828	13,442,050	79,678,878			79,678,878
23	Materials & Supplies	4,610,086	584,693	5,194,779			5,194,779
24	Other Working Capital	(11,516,764)	(2,246,433)	(13,763,197)			(13,763,197)
25	Deferred Income Taxes	(97,099,567)	580,542	(96,519,025)			(96,519,025)
26	Original cost rate base	$594,285,469	$26,073,214	$620,358,683	$0	$0	$620,358,683
27	Overall Rate of Return on Rate Base	6.86%		8.31%			8.90%

DOCKET NO. G-9, SUB 499
DOCKET NO. G-21, SUB 461
DOCKET NO. G-44, SUB 15
DOCKET NO. G-9, SUB 521

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., North Carolina Natural Gas, and Eastern North Carolina Natural Gas Company for the Consolidation of their Revenues, Rate Bases and Expenses, a General Increase in Rates and Charges, Approval of Various Changes to and Consolidation of their Rate Schedules, Classifications and Practices, and Approval of Depreciation Rates In the Matter of Application of Piedmont Natural Gas Company, Inc., for Approval of Semi-Annual Adjustment of Rates Under Appendix C of its Service Regulations	)	ORDER APPROVING RATE ADJUSTMENTS EFFECTIVE APRIL 1, 2006, AND DENYING MOTION OF ATTORNEY GENERAL

BY THE COMMISSION: On November 3, 2005, the Commission issued its Order Approving Partial Rate Increase and Requiring Conservation Initiative in a general rate case for Piedmont Natural Gas Company, Inc. (Piedmont), conducted in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15. Among other things, that Order approved the Customer Utilization Tracker (CUT) mechanism as an experimental, provisional tariff for Piedmont. The CUT mechanism provides that, beginning November 1, 2005, Piedmont shall compare actual margins recovered from residential and small and medium commercial customers with the margins in the rates approved in the general rate case and, on a semi-annual basis, shall apply for authority to implement temporary rate increments or decrements in order to collect or refund the differences.

On January 3, 2006, the Attorney General filed Notice of Appeal and Exceptions as to the November 3, 2005 Order. The exceptions and appeal relate to the Commission's approval of the CUT mechanism. The Attorney General's appeal has not yet been docketed with the North Carolina Supreme Court.

On March 17, 2006, Piedmont filed its first application pursuant to the CUT mechanism. The application was filed in Docket No. G-9, Sub 521. By this application, Piedmont requests authority to adjust rates effective April 1, 2006, by adding temporary rate increments to reflect the under-recovery of residential and small and medium commercial margins during the period November 1, 2005, through January 31, 2006. Piedmont has calculated the proposed temporary rate increments (temporaries) as a rate per dekatherm (dt) as follows:

Rate Description and Schedule	CUT Balance @ 1/31/2006	Temporaries ($/dt)
Residential (101 and 121)	$8,821,575	$0.2262
Small Commercial (102 and 132)	$2,892,978	$0.1230
Medium Commercial (152 and 162)	$51,104	$0.0086

The Public Staff presented this application to the Commission at the March 27, 2006 Commission Conference and recommended approval of Piedmont's proposed CUT rate increments. On that same date, the Attorney General filed a motion in all four dockets designated above, requesting that the application in Docket No. G-9, Sub 521 "be addressed by the Commission in Piedmont's general rate case docket[s] rather than a new docket or, in the alternative,...that the dockets be consolidated for consideration." The Attorney General also opposed the CUT rate increments proposed by Piedmont on the same grounds previously argued in the general rate case. Piedmont appeared at the Commission Conference and opposed the Attorney General's motion.

The Commission finds good cause to deny the motion of the Attorney General asking that the present CUT application either be considered in the general rate case dockets or consolidated therewith.[1] The order in the general rate case dockets resolved the issues raised in those proceedings, including approval of the CUT. The CUT provides for the filing of applications for rate adjustments every six months during the life of the tariff. Although the general rate case order did not specify how the semi-annual CUT applications should be filed, the Commission concludes that, for administrative convenience, it is appropriate that all such applications shall be filed in a single, new docket and that Docket No. G-9, Sub 521 shall be used for this purpose. This ruling is not intended to prejudice the Attorney General's appeal of the general rate case order in any way. The Rules of Appellate Procedure provide for consolidation of appeals involving common questions of law by motion to the appellate court wherein the appeals are docketed. N.C.R.App.P. 40.

The Commission further finds good cause to approve the CUT application filed by Piedmont on March 17, 2006. The Public Staff has reviewed the calculations by which Piedmont derived the proposed CUT rate increments, and the Public Staff recommended that the rate increments be approved as filed Although the Attorney General opposes the CUT on legal and policy grounds, he raised no issue as to the accuracy of Piedmont's calculations. The Commission finds that the application is consistent with the provisions of the CUT tariff, which has not been stayed pending appeal, and that it should be approved.

IT IS, THEREFORE, ORDERED as follows:

[1] The present order is being issued in all four dockets only because the Attorney General filed his motion in all four dockets. The provisions of the order approving the CUT rate adjustments should be regarded as issued in Docket No. G-9, Sub 521.

1. That Piedmont is allowed to implement rate increments as contained in the body of this Order effective for service rendered on and after April 1, 2006, in order to collect the balance in the Customer Utilization Tracker deferred account;

2. That Piedmont shall file an original and eleven copies of its revised tariffs consistent with Ordering Paragraph 1 within five days of the date of this Order;

3. That Piedmont shall give notice to its customers of the rate changes allowed in this Order;

4. That the motion filed by the Attorney General on March 27, 2006, should be, and hereby is, denied; and

5. That, for administrative convenience, Piedmont shall file all future CUT applications in Docket No. G-9, Sub 521.

ISSUE BY ORDER OF THE COMMISSION.
This the 28th day of March 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioners Sam J. Ervin, IV, and Lorinzo L. Joyner dissent as to approval of the CUT rate increments for the reasons stated in their dissents from the November 3, 2005 Order in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15. They join in the remainder of the Commission's order herein.

Ah032706.01

DOCKET NO. P-55, SUB 1577

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Complaint of dPi Teleconnect, L.L.C. Against	)	
BellSouth Telecommunications, Inc. Regarding	)	ORDER DENYING dPi's
Credit for Resale of Services Subject to Promotional	)	MOTION TO RECONSIDER
Discounts	)	

BEFORE: Commissioner James Y. Kerr, II, Presiding, and Commissioners Sam J. Ervin, IV, and Chair Jo Anne Sanford

APPEARANCES:

For dPi Teleconnect, L.L.C.:

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

Christopher Malish, Foster, Malish, Blair & Cowan, L.L.P., 1403 West Sixth Street, Austin, Texas 78703

For BellSouth Telecommunications, Inc.:

Edward L. Rankin, III, BellSouth Telecommunications, Inc., Post Office Box 30188, Charlotte, North Carolina 28230

Andrew D. Shore, BellSouth Telecommunications, Inc., 675 W. Peachtree Street NE, Suite 4300, Atlanta, Georgia 30375

For the Using and Consuming Public:

Robert S. Gillam and Ralph J. Daigneault, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On August 25, 2005, dPi Teleconnect, L.L.C. (dPi) filed a complaint against BellSouth Telecommunications, Inc. (BellSouth) seeking credit for resale of services subject allegedly to promotional discounts in accordance with their interconnection agreement. Among other things, dPi resells BellSouth's retail residential telephone services, some of which are subject to BellSouth promotional discounts. The discount dPi seeks credit for in this proceeding is the Line Connection Charge Waiver (LCCW), which BellSouth gave to customers that purchased certain packages or features.

It was dPi's belief that some of its customers met the requirements of the LCCW by obtaining at least two of the following features: blocking per-use call return, blocking repeat dialing, and blocking call tracing. BellSouth refers to these features by the codes BCR, BRD, and HBG, respectively. BellSouth charges customers for most custom calling features, but it furnishes BCR, BRD, and HBG to customers upon request, without charge. BellSouth believes that customers obtaining BCR, BRD, or HBG did not qualify for the discount because the promotion only provided the discount for purchased features.

On March 1, 2006, the Commission held an evidentiary hearing in Raleigh with witnesses from dPi and BellSouth presenting testimony and exhibits. On April 27, 2006, the Public Staff filed its Proposed Order and dPi and BellSouth filed briefs. On June 7, 2006, the Commission issued an Order Dismissing the Complaint.

On July 6, 2006, dPi filed a Motion for Reconsideration which can be summarized as follows:

a. dPi is entitled to recover $2,537.70 for credits wrongfully denied on the grounds that a transfer, rather than a winover or reacquisition, was involved.

b. Applying the correct test, or basing the decision on the best evidence in the record, inexorably leads to the determination that dPi is entitled to LCCW promotion pricing when it purchases Basic Local Service plus two of the BCR, BRD, and HBG Touchstar features.

The Commission subsequently issued an Order Requesting Comments from BellSouth and the Public Staff and requiring reply comments to be filed by dPi. Briefly summarized, the parties commented as follows:

<u>BellSouth Comments</u>

BellSouth contended that dPi failed to present anything new for the Commission to consider. It simply reiterated statements contained in its earlier brief. dPi's arguments were not persuasive the first time, nor are they now. dPi's claim is founded upon selective use of three months out of two years billing data. dPi has presented absolutely no substantive evidence that refutes the results of the statistically valid sampling analysis presented by BellSouth. As such, the Commission should deny dPi's request for payment of $2,537.70.

BellSouth recommended that the Commission reaffirm its ruling that dPi is not entitled under the terms of the parties' interconnection agreement to credits for BellSouth's Line Connection Charge Waiver Promotion because BellSouth does not and would not give the promotion to its own End Users with only basic service and free blocks.

<u>Public Staff Comments</u>

The Public Staff stated that it cannot confirm whether dPi's claims for $2,537.70 in credits for wrongfully denied transfers/winovers are legitimate without a review of each credit request submitted by dPi. The Public Staff recommended that Bellsouth should examine each credit request individually, without the use of a sampling procedure, to determine the correct amount of credits due. If the total credits due as a result of the recalculation are greater than the credits already granted to dPi, BellSouth should award the necessary additional credits; if they are lower, dPi should reimburse BellSouth for the excess credits it has received.

It was also the Public Staff's view that BellSouth should not be forced to allow promotional pricing for customers that subscribe to blocking services for which no charge is made, including

BCR, BRD, and HBG. The Public Staff believes these services did not serve to qualify a customer for BellSouth's promotion and agrees with the Commission's ruling.

dPi Reply Comments

In its Reply Comments, dPi reiterated its comments from its Motion to Reconsider that:

1. dPi is entitled to recover $2,537.70 for credits wrongfully denied on the grounds that a transfer, rather than a winover or reacquisition, was involved.

2. Applying the correct test, or basing the decision on the best evidence in the record, inexorably leads to the determination that dPi is entitled to LCCW promotional pricing when it purchases Basic Local Service plus two of the BCR, BRD, and HBG Touchstar features.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission's analysis on Reconsideration addresses the two core issues raised by the reconsideration motion—improper credits for transfers and interpretation of the interconnection agreement:

Improper Credits for Transfers. During the hearing, dPi witnesses Brian Bolinger and Steve Watson responded affirmatively to the following question by dPi's counsel in prefiled rebuttal testimony:

> So in short, this case is reduced to whether dPi is entitled to promotional credits when it orders Basic Service plus Touchstar block features because it has "purchase[d]... BellSouth Basic Service with at least [two] feature[s]" and thus has "qualif[ied] for a waiver of the local service fee." Tpp. 40, 111.

G. S. 62-73 provides that complaints may be made by any person having an interest in any act or thing done or omitted to be done by a public utility that is unjust and unreasonable. The burden of proof with respect to any such complaint shall be upon the Complainant to show that the public utility's rates, service, classification, rule, regulation or practice is unjust and unreasonable. G.S. 62-75. In this case, dPi has the burden to demonstrate to this Commission by the greater weight of the evidence that BellSouth's determination of the credits due to dPi was unjust and unreasonable.

In this case, BellSouth Witness Pat Tipton testified that BellSouth employed two procedures to determine transfer – related credits due to dPi. First, BellSouth sampled end user accounts submitted for promotional billing credit to determine if they would qualify for the promotion in question. If, during the course of review, BellSouth determined that a portion of the accounts did not qualify, BellSouth applied the resulting percentage of qualified accounts to the total credit amount requested to determine dPi's credit amount. Tp. 201. BellSouth issued credits to dPi based on the results of this sampling process for each month of the 22 month promotional period. Tp. 204, dPi Exh 4.

In the second procedure, BellSouth enlisted the services of Dr. Joseph B. Thomas, PhD in statistics, to develop a sampling procedure for the North Carolina accounts for which dPi was claiming promotional credits. Dr. Thomas determined the sample sizes for dPi promotional requests that would determine a statistical accuracy of 95% and a precision of +/- 5%. When applied to the LCCW credits requested by dPi, Dr. Thomas found that 64% of the North Carolina credits applied for by dPi did not qualify for the promotion. This result, when the margin of error is considered, compared favorably with the 66% denial rate that BellSouth actually utilized when denying dPi promotional requests based on the previously described sampling process. Tp. 206.

During the hearing, BellSouth contended that it was not required to examine each account submitted to determine if the accounts qualified for promotional credits. According to BellSouth, such verification is neither necessary nor required. Rather, in BellSouth's view, examination of a representative sample of the accounts submitted is a suitable substitute for determining the amount of credits due. Under those circumstances, one cannot expect that the numbers provided by BellSouth will correspond precisely with the actual numbers derived after an actual examination of the credit requests for each month. At best, the numbers can merely approximate, within a range, the numbers predicted by the sampling process employed by BellSouth and verified by Dr. Thomas. BellSouth contends and the Commission concludes that the sampling process employed by BellSouth was statistically valid.

According to dPi, the process employed by BellSouth resulted in dPi being shortchanged in the amount of $2,537.70. dPi now asks this Commission to award it additional credits in that amount. In support of this request, dPi noted that its review of the BellSouth sampling data revealed denials for the months of June, August and November, 2005 which were significantly higher than industry and company expected denials for transfers. These results led dPi to question the validity of the data derived from these samples and caused dPi to perform an audit of those months. The audit revealed the denial percentages derived from the audits' actual numbers were substantially less than the denial percentages derived from sampling.

dPi now contends that it did not receive credits that it was due because the sampling process utilized by BellSouth was flawed. We are not persuaded from the evidence provided by dPi that BellSouth's approach to calculating credits due yielded incorrect results and is therefore unjust or unreasonable.

In this case, BellSouth determined credits for dPi based on the sampling process described by Witness Tipton and validated by Dr. Thomas for each of the 22 months of the promotional period. dPi chose not to examine the results derived from this sampling process for 19 of the 22 months for which the promotion operated. That is, dPi did not audit each credit request submitted for the entire 22 months for which the promotion was featured, and the credits were calculated to reach this conclusion. Nor did dPi perform an audit for each of the 12 months in which the sample indicated that a transfer request was denied. Either audit would have been invaluable in determining whether the sampling process provided a realistic assessment of transfer based denials.

Instead of auditing the submittals in the manner previously suggested, dPi picked those months for audit which had extremely high denial rates for transfers and offered the most opportunity for errors favorable to dPi, and did not audit those months which had low or zero denial rates because of transfers which, presumably, would yield results more favorable to BellSouth. dPi's method of calculating the credits it was due was inherently flawed and does not account for those months in which the denial rate, as determined by the sample, was low or nonexistent; nor does it indicate if the denial rates derived from the sample for other reasons were inaccurate. As a result, we have no way of knowing if the sampling process employed by BellSouth is in error or if the abnormally high deviations are no more than an anomaly in the statistically accurate sampling process.

Stated more simply, we are unable to tell from this data whether the $2,537.70 deviation identified by dPi is offset by a similar deviation in the remaining 19 months of the promotion period in favor of BellSouth. Thus, even if we accept that those three months produced a discrepancy of $2,537.70, we cannot determine by the greater weight of the evidence that the "error" requires an adjustment to dPi's account because dPi has not proven that the discrepancy has not been offset at some other point in BellSouth's <u>statistically valid sample</u>. Thus, dPi has not met its burden of proving by the greater weight of the evidence that the result reached by BellSouth's sampling process is unjust or unreasonable. Therefore, dPi's request for additional credits must be denied.

<u>Interconnection Agreement Interpretation.</u> On June 7, 2006, the Commission issued an Order Denying dPi's Complaint against BellSouth to recover credits which it alleged had been wrongfully denied. In the Order, we stated:

> Under the clear language of this provision, promotions are only available if end users would have qualified for the promotion if the promotion had been provided by BellSouth directly. In Witness Tipton's testimony, she stated emphatically that BellSouth does not authorize promotional discounts to its End Users who only order basic services and the blocks provided by dPi. This fact was uncontested by dPi at the hearing and unrebutted in its post hearing brief. Thus, under the clear terms of the interconnection agreement and the facts of this case, dPi end users who only order blocking features are not eligible for the credits because similarly situated BellSouth End Users are not entitled to such credit. dPi's complaint should therefore be denied.

In its Motion for Reconsideration, dPi argues that the Commission's decision in this case rests upon the Commission's failure to accurately apply a provision of the parties' interconnection agreement which states:

> "Where available for resale, promotions will be made available only to End Users who would have qualified for the promotion had it been provided by BellSouth directly."

dPi argues that the Commission was required to interpret the promotion to determine whether the end-user would have qualified for the promotion. The argument that dPi is now making is identical to the argument that it made in the hearing and in the post hearing brief. In our Order of June 7th, we expressly rejected this approach. We stated that "the Commission concludes that we are not required to analyze and decide this case based on the language of the promotion. The fact is that BellSouth and dPi jointly agreed to methodology for determining the limits of <u>any</u> promotion in their voluntarily negotiated interconnection agreement." (emphasis in original) Further, we stated "Under the clear terms of the interconnection agreement and the facts of this case, dPi end users who only order blocking features are <u>*not*</u> eligible for the credits because similarly situated BellSouth End Users are not entitled to such credits." (emphasis in original) Although dPi challenges the credibility of the testimony offered by BellSouth concerning the manner in which BellSouth applies the promotion in question to its own customers, nothing in the record suggests that BellSouth applies the promotional language in any manner other than that described by BellSouth's witness. As a result, dPi has not offered any persuasive rationale that would lead this Commission to overturn its original determination in this regard. For that reason, dPi's motion to reconsider this issue is denied.

IT IS, THEREFORE, SO ORDERED that:

1. dPi's motion for the Commission to award it additional credits in the amount of $2,537.70 be denied.

2. dPi's motion to reconsider the Order of June 7, 2006 be denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of October, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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DOCKET NO. P-35, SUB 96

In the Matter of		
Application of MebTel, Inc. for Approval	)	RECOMMENDED ORDER
of a Price Regulation Plan Pursuant	)	APPROVING MODIFIED PRICE
to N.C. Gen. Stat § 62-133.5(a)	)	REGULATION PLAN

HEARD: Thursday, September 13, 2006, in the Council Chambers, Mebane Municipal Hall, 106 East Washington Street, Mebane, North Carolina

BEFORE: Hearing Examiner Dan Long, Presiding

APPEARANCES:

FOR MEBTEL, INC.:

Daniel C. Higgins
Burns, Day & Presnell, P.A.
2626 Glenwood Ave., Ste. 560
Raleigh, North Carolina 27608

FOR THE USING AND CONSUMING PUBLIC:

Kendrick C. Fentress
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4326

BY THE HEARING EXAMINER: 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 the 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."

G.S. 62-133.5(a) requires notice and a hearing, allows different forms of price regulation as between different LECs, and requires the Commission to decide price regulation cases within 90 days subject to an extension by the Commission for an additional 90 days, or a total of 180 days from the filing of the Application. The statute requires the Commission to approve price regulation 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 that the Commission may adopt;

(iii) will not unreasonably prejudice any class of telephone customers, including telecommunications companies; and

(iv) is otherwise consistent with the public interest.

MebTel, Inc. ("MebTel") is currently operating pursuant to the price regulation plan that was the subject of the Commission's Order Approving MebTel's Price Regulation issued in this docket on September 10, 1999 (the "Original Plan"), as subsequently amended. G.S. 62-133.5(c) provides that "[a]ny 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." The Commission must approve the amended plan if it satisfies the four criteria quoted above. G.S. 62-133.5(c) further provides: "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."

On June 1, 2006, MebTel and the Public Staff – North Carolina Utilities Commission ("Public Staff"), collectively referred to as the "Parties," filed a Stipulation and Agreement with the Commission. In the Stipulation and Agreement, the Parties mutually agreed that the Small Local Exchange Carrier Price Regulation Plan for MebTel attached to the Stipulation (the "Stipulated Plan" or "Plan") met and satisfied the four statutory criteria for Commission approval of a price regulation plan under G.S. 62-133.5(c) and requested Commission approval. MebTel advised the Commission that its Stipulated Plan was substantially identical to the revised price regulation plans recently approved by the Commission for other local exchange companies.

The Stipulated Plan modified the Original Plan with the following provisions:

- Reclassification of existing services into five (5) new categories of service designated as Moderate Pricing Flexibility, Interconnection Services, Discretionary Pricing Flexibility, High Pricing Flexibility, and Total Pricing Flexibility.

- Services that would be classified in the Moderate Pricing Flexibility category include business and residential basic local exchange services. Prices for 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.

- Services that would be classified in the Interconnection Services category include Carrier Common Line, Switched Access Service, and the IntraLATA Toll Originating Responsibility Plan (ITORP). Prices for 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.

- Initially, there would be no services that would be classified to the Discretionary Pricing Flexibility category. Prices for services placed into the Discretionary Pricing

Flexibility category will be no higher than tariff rates but may be reduced to individual customers, for competitive reasons, below tariff rates at MebTel's discretion.

- Services that would be classified to the High Pricing Flexibility category include operator assisted local calls and optional business and residential calling features. Prices for these services could be increased by a maximum of 20% in each Plan year, provided that revenues for the category do not increase by more than two and one-half times the rate of inflation.

- Services in the Total Pricing Flexibility category include Centrex service. Prices for these services would not be regulated by the Plan.

- Financial penalties to be paid to customers if MebTel fails to meet service objectives established by the Commission.

On June 27, 2006, the Commission issued its Order Scheduling Hearing, Requiring Public Notice, And Submission of Prefiled Testimony. This Order consolidated the public hearing and the evidentiary hearing for September 13, 2006, with respect to MebTel's request for approval of the Stipulated Plan. The Order required that MebTel publish notice of the hearing in newspapers having general circulation in the Mebane, Milton and Gatewood exchange areas once a week during the weeks of July 31 and August 7, 2006; that MebTel send the Notice to its customers by means of bill inserts or special direct mailing between August 1 and August 10, 2006; that petitions to intervene be filed no later than August 17, 2006; that MebTel prefile direct testimony no later than August 22, 2006; that the Public Staff and any other intervener prefile direct testimony no later than September 1, 2006; that rebuttal testimony be filed no later than September 8, 2006; and that all the parties in this docket file witness lists, proposed order of witnesses and estimated cross-examination times no later than September 8, 2006.

On August 22, 2006, MebTel filed the direct testimony of Stephen Murray, Director of Regulatory Affairs for MebTel. On August 22, 2006, MebTel also filed affidavits of publication establishing that public notice had been provided in accordance with the Commission's procedural order. On September 1, 2006, the Public Staff filed the direct testimony of Charles B. Moye, an Engineer with the Communications Division. Both witnesses supported the Stipulated Plan.

At the September 13, 2006 evidentiary hearing in Mebane, the Parties were present, as well as members of the public. The public witnesses consisted of Montrena Hadley, Ken Creager, and Steve Cole, who testified without objection. All three public witnesses testified in support of MebTel, complimenting its service. At the conclusion of the public hearing, MebTel witness Murray and Public Staff witness Moye testified without objection.

On September 22, 2006, the North Carolina Attorney General filed a Notice of Intervention and a Brief in this docket. In his brief the Attorney General expressed his belief that the Commission should not approve the Stipulated Plan on the grounds that it was contrary to the public interest and unnecessary for MebTel to compete fairly.

MebTel and the Public Staff filed a Joint Proposed Order on October 4, 2006.

WHEREFORE, based on the foregoing, the evidence adduced at the hearing, and the entire record in this matter, the Hearing Examiner now makes the following

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. MebTel is a "local exchange company" as the term is defined in G.S. 62-3(16a). MebTel is currently subject to a price regulation plan pursuant to the provisions of G.S. 62-133.5(a) 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 MebTel 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.

EVIDENCE FOR 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.

EVIDENCE FOR 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 testimony and exhibits of MebTel witness Murray and Public Staff witness Moye. The Hearing Examiner has also taken into account the testimony of public witnesses Hadley, Creager and Cole.

MebTel witness Murray testified as to the economic rationale for revising MebTel's Original Plan; the economic context in which the stipulated revisions to the Original Plan should be evaluated; the changes in competitive landscape for telecommunications services in the United States and North Carolina; the effects of new technology and increased competitive options; and the entry of larger companies such as Time Warner. In addition, witness Murray explained why MebTel sought to make the modification to the Original Plan. Specifically, witness Murray testified that the Stipulated Plan would enable MebTel to more quickly react to competitive pressures and changing customer expectations and demand. The flexibility provided for in the Stipulated Plan could provide immediate as well as long-term benefits to many of MebTel's customers and would allow MebTel to better meet competitive challenges within its territory.

In his direct testimony, witness Murray discussed the detailed provisions of the Stipulated Plan, explained why the Plan is consistent with the requirements of G.S. 62-133.5(a), and stated that it represents a compromise supported by representatives of the using and consuming public and MebTel. Witness Murray's testimony provided evidence that MebTel has experienced loss of access lines to competition, that such losses continue, and that the prospect for future losses through competition is high. Witness Murray testified to the significant risk for traditional wireline local telephone companies from competition from wireless and Voice over Internet Protocol ("VoIP") providers.

Public Staff witness Moye also testified that developments have changed the landscape of the telecommunications industry in North Carolina since local competition was authorized by state and federal law. Specifically, witness Moye described these changes as the growth in access line competition from competing local providers ("CLPs"); the growth in wireless service; the halt and possible permanent reversal of access line growth for incumbent LECs; and the potential for further competition from new technologies. In addition, witness Moye testified that the Stipulated Plan satisfies the criteria of G.S. 62-133.5(a). Like MebTel witness Murray, Mr. Moye testified that the Stipulated Plan is a reasonable compromise between MebTel and the Public Staff. The testimony of witnesses Murray and Moye establishes that, for many services in MebTel's service areas, price constraints imposed by the existence of competitors are current, real and generally effective, aiding the Commission's determination that the Stipulated Plan will result in affordable rates.

In Commission Rule R17-1(a) the Commission has defined basic local exchange service 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." In the Stipulated Plan basic local exchange service is included in the Moderate Pricing Flexibility Services category. However, the Stipulated Plan allows MebTel 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 a productivity offset of zero. The constraint for the High Pricing Flexibility Services category is set at two and one-half times the GDPPI minus the offset.

As witness Moye noted, the rate element constraints are based on a set percentage. Under the Stipulated Plan, the rate element constraint is 10% in the Moderate Pricing Flexibility Service category and the Interconnection Services category. In the High Pricing Flexibility Services category the rate element constraint is 20%. The Stipulated Plan also includes a minimum increase provision, under which any rate element in the Moderate Pricing Flexibility Services category may be increased on an annual basis by a minimum of ten percent (10%) or thirty-five cents ($0.35), whichever is greater, if it is priced on a flat-rated monthly basis, and 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 High Pricing Flexibility Services category with the following allowed minimum rate increases: twenty percent (20%) or fifty cents ($0.50), whichever is greater, for rate elements priced on a flat-rated monthly basis, and twenty percent (20%) or thirty cents ($.30), whichever is greater, for rate elements priced on a per-use basis.

The Attorney General opposed the increased pricing flexibility on the basis that MebTel and the Public Staff have failed to show that the increases are necessary for MebTel to compete fairly.

Notwithstanding the position taken by the Attorney General, the Hearing Examiner concludes that the incremental increase in pricing flexibility is appropriate while still protecting the affordability of basic local exchange service. Prices for Moderate Pricing Flexibility Services in the aggregate can increase no more than the one and one half times the change in GDPPI. Aggregate price increases for rate elements in this category above this rate 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 ten percent (10%) for basic and twenty percent (20%) for non-basic service.

In reaching this conclusion, the Hearing Examiner notes that MebTel's Original Plan was approved almost seven years ago under competitive circumstances very different from those in existence today. The record shows that in the past five years, MebTel has continued to lose access lines, as a result of changes in technology and competition. In contrast, when MebTel's current rates were adopted there was no competition for basic service. The limited increase in pricing flexibility allowed under the Stipulated Plan for basic local exchange services and discretionary services is fully justified by the increased competition that exists in MebTel's North Carolina telecommunications market. It is also consistent with increased pricing flexibility approved for other North Carolina incumbent LECs.

EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO. 3 - SERVICE QUALITY

Finding of Fact and Conclusion of Law No. 3 was not disputed by any party. The Original Plan did not contain specific service quality measurements and self-enforcing service penalties. In contrast, in the Stipulated Plan there are provisions expressly relating to service quality measurements and provision for appropriate service quality penalties. The Commission retains powers and authority with regard to the provision of quality service. MebTel 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 Hearing Examiner concludes that the Stipulated Plan reasonably assures the continuation of basic local exchange service that meets the reasonable service standards established in Commission Rule R9-8.

EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO. 4 - NO PREJUDICE AMONG CUSTOMER CLASSES

MebTel witness Murray's testimony addressed the issue of whether the Stipulated Plan will unreasonably prejudice any class of telephone customers. He stated that, for several reasons, the Stipulated Plan will not result in such prejudice. First, he asserted that MebTel will continue to charge tariffed rates for services on non-discriminatory terms and conditions and that those prices will be restrained by the Stipulated Plan's pricing limits and by competition.

Second, customers in a position to negotiate customer-specific agreements will obtain prices that are constrained by the existence of competitive alternatives.

Third, the Stipulated Plan does not change any terms and conditions applicable to MebTel's relationships with other carriers, such as the terms of access tariffs, interconnection agreements, or wholesale service arrangements and numbering, and applicable nondiscrimination requirements remain in effect.

Finally, the Stipulated Plan uses existing rates as a starting point and therefore preserves the pricing for basic residential services. At the same time, the Stipulated Plan permits MebTel to modify its basic residential prices, over time, without necessarily making corresponding changes in basic business prices that begin at higher levels. In this way, the Stipulated Plan preserves a balance between the treatment that residential customers have traditionally enjoyed and the possibility that basic business rates may require a somewhat different treatment in the future because they are more competitive.

Public Staff witness Moye did not take issue with witness Murray's analysis and agreed that the Stipulated Plan will not be unreasonably prejudicial to customers.

The Hearing Examiner finds the testimony of witnesses Murray and Moye to be persuasive and concludes that the Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO. 5 - PUBLIC INTEREST STANDARD

The public interest standard is one the Commission has employed in its deliberations for many years. The Hearing Examiner 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 MebTel will continue to provide adequate service to its customers. Third, the Stipulated Plan contains specific service performance measures and penalties. Fourth, the Hearing Examiner 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.

At the same time, the Hearing Examiner 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 had not yet progressed to the point where it could discipline prices effectively in MebTel's service areas.

In addressing this concern, the Hearing Examiner 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 MebTel's service areas. The assignment of services to categories in the Stipulated Plan was determined by negotiation between MebTel and the Public Staff and based on previously approved plans of other incumbent local exchange providers. 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 Hearing Examiner 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 agreed 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 public interests standards, 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 Hearing Examiner notes that three public witnesses testified in favor of the Company and the Stipulated Plan.

The Hearing Examiner further notes that the Attorney General expressed concerns about the pricing flexibility in the Stipulated Plan being contrary to the public interest in his brief. The Attorney General, however, submitted no evidence to support his concerns; and it is the Hearing Examiner's evaluation that the Attorney General has not recognized the dramatic change in competitive circumstances that have occurred since MebTel's first plan was adopted which have tended to diminish the need for direct regulatory supervision over prices.

The Hearing Examiner concludes that the Stipulated Plan is consistent with the public interest given the current level of competition in MebTel's service areas. Furthermore, the Hearing Examiner recognizes that, under the Stipulated Plan, the Commission retains the regulatory oversight authority for any request by MebTel 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.

FINAL OBSERVATIONS AND CONCLUSIONS

Consistent with the law and policy of this State, MebTel 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 Hearing Examiner 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 1996. The Hearing Examiner believes that the flexibility afforded by the Stipulated Plan will enable MebTel to compete effectively and continue to provide reasonably affordable basic local exchange service. The Hearing Examiner's decision to approve the Stipulated Plan is based upon its analysis of competitive conditions in MebTel's service territory, and should not be understood as indicating that a different plan would not be appropriate given the existence of different competitive conditions.

IT IS, THEREFORE, ORDERED that the Stipulated Plan be, and the same is hereby approved for implementation by MebTel effective no later than October 25, 2006, provided that MebTel shall, not later than October 24, 2006, refile the Stipulated Plan bearing an effective date not later than October 25, 2006.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of October, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb100606.01

DOCKET NO. P-55, SUB 1549

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Proceeding to Consider Amendments to	)	
Interconnection Agreements Between	)	ORDER RULING ON
BellSouth Telecommunications, Inc.	)	OBJECTIONS
and Competing Local Providers Due to	)	
Changes of Law	)	

BEFORE: Commissioner James Y. Kerr, II, Presiding, and Commissioners Sam J. Ervin, IV, Lorinzo L. Joyner, and Howard N. Lee

BY THE COMMISSION: On March 1, 2006, the Commission issued its *Order Concerning Changes of Law* (the *Change of Law Order*) in this docket. The Commission made the following Findings of Fact:

1. Language implementing the *TRRO* [*Triennial Review Remand Order*] transition should require the identification and physical reconfiguration of affected unbundled network elements (UNEs) as soon as practicable, impose transition rates throughout the applicable transition periods, require notification of end users where applicable, identify wire centers in accordance with Finding of Fact No. 5, require that CLPs [competing local providers] be notified of affected wire centers, and provide for the self-certification and protest process that is currently in place.

2. BellSouth [BellSouth Telecommunications, Inc.] and the CLPs should be required to execute amendments to their ICAs [interconnection agreements] deleting the provisions requiring BellSouth to offer the UNEs that the FCC [Federal Communications Commission] has found are no longer required to be offered under Section 251(c)(3) of the Telecommunications Act of 1996 (the Act or TA96). Unless the parties mutually agree on different language, the language of the amendments must be as set forth in this Order; or, if no specific language is set forth in this Order, it must be consistent with the Commission's conclusions. The decisions reached in this Order will be controlling in all pending arbitration proceedings involving BellSouth, and, unless the parties agree on different language, the language approved in this Order should be included in any ICA currently under negotiation.

3. The definitions contained in FCC Rule 51.5 for business line and fiber-based collocator are appropriate for inclusion in interconnection agreements. The definition of building as modified and proposed by CompSouth [the Competitive Carriers of the South] witness Gillan is appropriate. The definition of route in FCC Rule 51.319(e) should be adopted with a clarification regarding wire centers and reverse collocation facilities, as proposed by Sprint [Sprint Communications Company, L.P.] witness Maples. The parties may adopt a verbatim recitation of the FCC's threshold rules or simply reference them in the ICA, in order to incorporate BellSouth's obligation to offer unbundled access to high-capacity loops and dedicated transport in ICAs.

4. The Commission has the authority, in this situation wherein there is a dispute, to determine whether or not BellSouth's application of the FCC's Section 251 nonimpairment criteria for high-capacity loops and transport is appropriate.

5. In determining the number of business lines, it is inappropriate for BellSouth to expand its count of its switched access business lines to count full system capacity. The number of switched business access lines reported in Automated Reporting Measurement Information System (ARMIS) should be used. In addition, it is inappropriate for BellSouth to include residential unbundled network element – loop (UNE-L) lines in the count of business lines. Further, it is inappropriate for BellSouth to expand its count of high-capacity UNE-L to count full-system capacity. Instead, BellSouth should use the same utilization factor for CLP high-capacity UNE-L as exists for BellSouth's high-capacity lines. Finally, it is appropriate for BellSouth to count the number of lines provided via HDSL [high-bit-rate digital subscriber line], asymmetrical digital subscriber line (ADSL), unbundled copper loop – short (UCL-S), and integrated services digital network (ISDN) digital subscriber line (IDSL) loops on a one-for-one basis.

6. The parties should negotiate appropriate language to include in the interconnection agreements which reflects the procedures outlined by the Commission in Finding of Fact No. 5 concerning the calculation of business lines. After the nonimpairment wire center list is established, CLPs should not be able to self-certify that they are entitled to obtain high-capacity loops and transport on an unbundled basis in a wire center where they are not impaired. Further, it is appropriate for BellSouth to only include the initial nonimpaired wire center list in its interconnection agreements and simply to make a reference in the interconnection agreements to BellSouth's Carrier Notification Letters as posted on its website for the latest wire center list. BellSouth's proposed process for developing future nonimpaired wire center lists by posting a Carrier Notification Letter is appropriate, however, BellSouth should not be required to unbundle new high-capacity loops or transport 30 business days after posting a Carrier Notification Letter. Finally, high-capacity loops and transport UNEs that are in service when a subsequent wire center determination is made should remain available as UNEs for one-half of the original transition period, with the clock starting to tick the day BellSouth posts the Carrier Notification Letter.

7. HDSL-capable loops are not equivalent to DS1 [Digital Signal 1] loops for the purpose of evaluating impairment.

8. The Commission does not have the authority to require BellSouth to include Section 271 elements in ICAs entered into pursuant to Section 252, nor does the Commission have the authority to set rates for such elements.

9. No conditions should be imposed on moving, adding, or changing orders to a CLP's respective embedded base of switching except those described in 47 C.F.R. § 51.319(d)(2). However, Rule 51.319(d)(2)(iii) requires BellSouth to provide unbundled switching to a CLP's embedded base of end-user customers until March 11, 2006. No conditions should be imposed on moving, adding, or changing orders to a CLP's high-capacity loops except those described in 47 C.F.R. § 51.319(a). No conditions should be imposed on moving, adding, or changing orders to a CLP's dedicated transport except those described in 47 C.F.R. § 51.319(e).

10. Any service arrangements delisted by the FCC in the *TRO* [*Triennial Review Order*] should be removed from ICAs as Section 251 UNE offerings effective with the *TRO* amendment. BellSouth should not impose disconnection or nonrecurring charges when transitioning the delisted Section 251 UNEs to alternate services. The issue of future delisting is addressed in Finding of Fact 6.

11. In instances where BellSouth has tariffed alternatives to a delisted UNE, and the CLP does not submit conversion orders or spreadsheets to BellSouth prior to the end of the transition period, such UNEs should be converted to the appropriate tariffed rate effective on the day following the end of the FCC-specified transition period. No disconnection charges should apply, and in cases where no physical rearrangements are necessary for conversion, no tariffed nonrecurring charges should apply. For services for which no tariffed offering exists, BellSouth must provide each CLP a spreadsheet or order as soon as possible prior to the end of the transition period listing the services for which no order has been placed, together with a notice that the services will be disconnected on the day after the end of the transition period.

12. With the Commission's approval of the new, stipulated Service Quality Measurement (SQM) / Self-Effectuating Enforcement Mechanism (SEEM) plan in Docket No. P-100, Sub 133k, effective November 15, 2005, the issue in this docket of removing delisted UNEs from the SQM/Performance Measurements and Analysis Platform (PMAP)/SEEM plan is moot.

13. Section 271 offerings can be commingled with Section 251 UNE offerings. The cost of multiplexing equipment should be based on the cost of the higher speed element associated with the multiplexing equipment. Rates for commingling should remain at total element long-run incremental cost (TELRIC) prices for Section 251 UNEs and just and reasonable market prices for Section 271 elements.

14. BellSouth is required to provide conversion of special access circuits to UNE pricing. The contract language concerning the "Conversion of Wholesale Services to Network Elements or Network Elements to Wholesale Services", as proposed by CompSouth witness Gillan, in his First Revised Exhibit JPG-1, should be adopted. The conversions should be made pursuant to the terms of the ICA. The switch-as-is conversion rates proposed by BellSouth, in its December 5, 2005 filing, are the appropriate rates.

15. The rates, terms, and conditions for conversions should be retroactive back to the *TRO* effective date, except that requests for conversions that were pending as of the effective date of the *TRO* should be processed under the conditions that existed prior to the *TRO*.

16. The Commission concludes that, since it has decided in Finding of Fact No. 8 that it does not have the authority to require BellSouth to include Section 271 elements in ICAs entered into pursuant to Section 252, nor have the authority to set rates for such elements, it will not rule on whether BellSouth is obligated pursuant to the Act and FCC Orders to provide line sharing to new customers after October 1, 2004 under its Section 271 obligations.

17. ICAs should only contain language for line sharing transitioning from CLPs' existing Section 251 line sharing arrangements.

18. In accordance with the Commission's decision on Matrix Item No. 14 (Finding of Fact No. 13), line splitting should be allowed on a commingled arrangement of a Section 251 loop and unbundled local switching pursuant to Section 271. BellSouth and CompSouth should negotiate acceptable language to address whether a CLP should indemnify BellSouth for "claims" or "claims and actions" arising out of actions by the other CLP involved in the line splitting arrangement. It is appropriate to adopt Section 3.8.15 from CompSouth's First Revised Exhibit JPG-1 concerning access to operations support systems (OSS). Finally, BellSouth is not obligated to provide CLPs with

access to BellSouth-owned splitters, however, CompSouth's proposed language in Section 3.6.13 of CompSouth's First Revised Exhibit JPG-1 is acceptable.

19. Consistent with its ruling in Finding of Fact No. 8, the Commission concludes that it does not have the authority to require BellSouth to include call-related databases provided pursuant to Section 271 in ICAs entered into pursuant to Section 252.

20. The following Sections should be incorporated into the *TRRO* amendments:

2.1.2.1.1 Fiber to the Home (FTTH) loops are local loops consisting entirely of fiber optic cable, whether dark or lit, serving an End User's premises or, in the case of predominantly residential multiple dwelling units (MDUs), a fiber optic cable, whether dark or lit, that extends to the MDU minimum point of entry (MPOE). Fiber to the Curb loops are local loops consisting of fiber optic cable connecting to a copper distribution plant that is not more than five hundred (500) feet from the End User's premises or, in the case of predominantly residential MDUs, not more than five hundred (500) feet from the MDU's MPOE. The fiber optic cable in a FTTC loop must connect to a copper distribution plant at a serving area interface from which every other copper distribution subloop also is not more than five hundred (500) feet from the respective End User's premises. BellSouth shall offer CLECs unbundled access to FTTH/FTTC loops serving enterprise customers and predominantly business MDUs.

2.1.2.1.2 In new build (Greenfield) areas, where BellSouth has only deployed FTTH/FTTC facilities, BellSouth is under no obligation to provide such FTTH and FTTC Loops. FTTH facilities include fiber loops deployed to the MPOE of a MDU that is predominantly residential regardless of the ownership of the inside wiring from the MPOE to each End User in the MDU.

2.1.2.3 Notwithstanding the above, nothing in this Section shall limit BellSouth's obligation to offer CLECs an unbundled DS1 loop (or loop/transport combination) in any wire center where BellSouth is required to provide unbundled access to DS1 loops and loop/transport combinations.

21. The following language should be adopted for the *TRRO* amendments to address BellSouth's hybrid loop unbundling obligations:

2.1.3 A hybrid loop is a local loop, composed of both fiber optic cable usually in the feeder plant and cooper twisted wire or cable usually in the distribution plant. BellSouth shall provide unbundled access to hybrid loops pursuant to the requirements of 47 C.F.R. 51.319(a)(2).

22. The language proposed by Sprint witness Maples, in his rebuttal testimony, for Section 1.10 of the *TRRO* amendments should be adopted to implement BellSouth's obligation to provide routine network modifications (RNMs).

23. Sprint witness Maples' amended version of Section 1.10 of the *TRRO* amendments, previously adopted in Finding of Fact 22, adequately addresses the appropriate charges for RNMs. Such language will provide BellSouth with the flexibility to price network modifications on an individual case basis in the event that existing rates do not cover a particular situation.

24. The following language should be adopted for Section 2.1.2.2 of the *TRRO* amendments to address issues relating to fiber to the home and fiber to the curb:

> 2.1.2.2 In FTTH/FTTC overbuild situations where BellSouth also has copper Loops, BellSouth will make those copper Loops available to <<customer_short_name>> on an unbundled basis pursuant to the requirements of 47 C.F.R. § 51.319(a)(3)(iii). BellSouth's retirements of copper loops or copper subloops must comply with the requirements of 47 C.F.R. § 51.319(a)(3)(iv).

25. Thirty to forty-five days' advance notice of an audit provides a CLP with an adequate time to prepare. In its Notice of Audit, BellSouth shall state its concern that the requesting CLP has not met the qualification criteria and set out a concise statement of the reasons therefore. BellSouth may select the independent auditor without the prior approval of the CLP or the Commission. Challenges to the independence of the auditor may be filed with the Commission only after the audit has been concluded. BellSouth is not required to provide documentation, as distinct from a statement of concern, to support its basis for an audit, or seek the concurrence of the requesting carrier before selecting the location of the audit.

26. The *Core Order* removed the "growth caps" and "new markets" reciprocal compensation restrictions and should be implemented in ICAs. The language set forth in Exhibit JW-1 should be used as a guide by parties to remove the "growth caps" and "new markets" restrictions wherever such restrictions are included in ICAs. Such language need not be used where the parties adopt negotiated language to implement the *Core Order*, or where the right to amend an ICA to implement the *Core Order* has been waived through a party's failure to make a request by a deadline specified in the ICA. Amendments to ICAs to implement the *Core Order* should be included with the *TRO/TRRO* amendments.

27. BellSouth and all CLPs with whom it has ICAs currently in effect should execute and file amendments to the ICAs that are consistent with the provisions of this Order, or are mutually agreeable to the parties to the ICA, by March 10, 2006.

On March 31, 2006, BellSouth filed its Motion for Reconsideration and Clarification of certain findings in the *Change of Law Order*. Specifically, BellSouth requested reconsideration or clarification of Findings of Fact Nos. 5, 13, 15, 18, and 20.

On April 4, 2006, the Commission issued an *Order* requesting comments and reply comments on the Motion for Reconsideration and Clarification filed concerning the *Change of Law Order*. On April 17, 2006, the Public Staff filed a Motion for Extension of Time to File Initial Comments and Reply Comments in this regard. The Public Staff's Motion was granted by Order dated April 18, 2006, and initial comments were due by no later than April 26, 2006, and reply comments were due by no later than May 10, 2006.

Initial comments were filed on April 26, 2006 by CompSouth[1] and the Public Staff.

BellSouth requested three separate extensions of time to file reply comments. On June 6, 2006, BellSouth filed a letter in lieu of formal reply comments.

Following is a discussion, by Finding of Fact, of the outstanding Objections to the *Change of Law Order.* Appendix A provides a list of the acronyms used in this *Order.*

<u>FINDING OF FACT NO. 5 (ISSUE NO. 5 – MATRIX ITEM NO. 5(b))</u>: *TRRO*/FINAL RULES – What procedures should be used to identify those wire centers that satisfy the FCC's Section 251 nonimpairment criteria for high-capacity loops and transport?

INITIAL COMMISSION DECISION

The Commission concluded that:

(a) it is inappropriate for BellSouth to expand its count of its switched access business lines to count full system capacity. The number of switched business access lines reported in ARMIS should be used;

(b) it is inappropriate for BellSouth to include residential UNE-L lines in the count of business lines;

(c) it is inappropriate for BellSouth to expand its count of high-capacity UNE-Ls to count full system capacity. Instead, BellSouth should use the same utilization factor for CLP high-capacity UNE-Ls as exists for BellSouth's high-capacity lines; and

(d) it is appropriate for BellSouth to count the number of lines provided via HDSL, ADSL, UCL-S, and IDSL loops on a one-for-one basis.

MOTION FOR RECONSIDERATION

BELLSOUTH: BellSouth objected to Finding of Fact No. 5, stating that the Commission's decision to disallow the inclusion of full system capacity of BellSouth's switched access lines and CLP UNE-L lines is not consistent with the FCC's directives. BellSouth maintained that the Commission's decision concerning how business lines should be counted for purposes of the FCC's impairment tests states that it will "focus on the FCC's directives in calculating business lines found in the *TRRO* and Rule 51.5 . . . " BellSouth stated that the Commission also makes clear that it seeks to follow "the directives of the FCC . . ." BellSouth asserted that, however, the Commission concluded that BellSouth should not expand its count of either switched access business lines or high-capacity UNE lines to include full system capacity. BellSouth maintained that the Commission's decision to

[1] CompSouth's members include the following companies participating in this proceeding: Access Point Inc., Cbeyond Communications, LLC, Cinergy Communications Company, Dialog Telecommunications, DIECA Communications, Inc., d/b/a Covad Communications Company, FDN Communications, IDS Telcom, LLC, InLine, ITC^DeltaCom, LecStar Telecom, Inc., Momentum Telecom, Inc., Navigator Telecommunications, LLC, NuVox Communications, Inc., Supra Telecom, Talk America (and Network Telephone, a Talk America company), Trinsic Communications, Inc., XO Communications Services, Inc., and Xspedius Communications, LLC.

disallow the inclusion of full system capacity for BellSouth's switched access lines and CLP UNE-L lines is not consistent with the FCC's directives.

BellSouth argued that, to properly implement the FCC's directives, the full system capacity of both BellSouth's switched access lines and CLP high-capacity loops must be used. BellSouth noted that, in other words, if BellSouth has a switched DS1 line in service, it should count as 24 lines; likewise, if a CLP has a DS1 UNE in service, it also counts as 24 lines. BellSouth maintained that this is the correct method of counting business lines because the FCC has made it clear that "a DS1 line corresponds to 24 64 kbps [kilobits per second]-equivalents, and therefore to 24 'business lines'." BellSouth asserted that the FCC reiterated its intention to count the full system capacity of business lines in appellate papers filed in the United States Court of Appeals, District of Columbia Circuit, in which the FCC explained that "[t]he [FCC's] test requires ILECs [incumbent local exchange companies] to count business lines on a voice grade equivalent basis. *In other words, a DS1 loop counts as 24 business lines, not one.*" [Emphasis added.] BellSouth argued that neither the federal rules nor the FCC's appellate papers limit the calculation of business lines to what is *in service* – instead, the clear directive is to count a DS1 line as 24 lines.

BellSouth maintained that, indeed, the FCC's test cannot reasonably be implemented otherwise if the directive to use business lines as a proxy for revenue opportunities is to be realized. BellSouth stated that this is because the FCC sought to capture actual *and potential competition* (*TRRO*, Paragraphs 87 and 88) and also made it clear that it wanted to identify *potential revenue and revenue opportunities* (*TRRO*, Paragraphs 86, 87, 88, 93, 94, 95, 103, 129, 130, and 168). BellSouth argued that limiting the business line calculation to lines that are actually in use would fail to evaluate potential competition and potential revenue. BellSouth noted that a simple analogy makes this clear – in shopping for homes, many prospective homeowners request a certain number of bedrooms. BellSouth stated that newlyweds may elect a three bedroom home, for example, anticipating that they may have children. BellSouth maintained that such a home would not be considered a one-bedroom home, simply because a young couple only uses one bedroom until children arrive. Instead, BellSouth maintained, the home would properly be considered a three-bedroom home. BellSouth stated that the same holds true for high-capacity business lines – a business may order a switched DS1 line from BellSouth anticipating that it will grow into the full capacity. BellSouth noted that a CLP may order a UNE DS1 loop to meet its end user's needs. BellSouth asserted that, in either case, the FCC's directive is clear – such a line counts as 24 lines, not some other number, in order to capture both potential competition and potential revenue.

BellSouth also requested that the Commission reconsider its decision to disallow residential UNE-L lines in the count of business lines. BellSouth requested reconsideration of this aspect of the Commission's ruling for three reasons. BellSouth stated that, first, the Commission's ruling is inconsistent with the evidentiary record. Second, BellSouth stated that it cannot practicably implement this aspect of the Commission's ruling. Third, BellSouth maintained that its customer of record for the UNE-L – the CLP – is a business customer.

BellSouth noted that, with respect to the evidentiary record, the primary CLP witness in this case – Joseph Gillan – testified during his deposition that he did not think it would be worth correcting BellSouth's business line count to exclude residential DS0 loops (which would be the loop type used to serve residential customers). BellSouth maintained that witness Gillan stated that it was not worth correcting BellSouth's business line count to exclude residential DS0 loops because "it's such a small number . . . trying to do it correctly wouldn't be worth it." Thus, BellSouth argued, although the

CLPs disagreed with BellSouth's inclusion of residential lines, their legal position conflicts with the evidentiary record. BellSouth asserted that the Commission's *Change of Law Order* does not reconcile this conflict and should be reconsidered on that basis.

BellSouth maintained that, as further grounds for reconsideration, BellSouth cannot practicably implement this aspect of the *Change of Law Order*. BellSouth stated that witness Gillan acknowledged that fact in his deposition when he stated "you [referring to BellSouth] just – you don't know whether or not those lines are used to provide switched business service." BellSouth stated that, as a practical matter, BellSouth's records do not contain any class of service indicators for UNE-L lines; thus, BellSouth cannot simply recalculate business line numbers to exclude residential UNE-Ls. BellSouth maintained that this contrasts with residential unbundled network element – platform (UNE-P) lines, which BellSouth did exclude from its calculations, and which have class of service indicators that allow for the exclusion of these lines in implementing the FCC's test. BellSouth asserted that, in seeking reconsideration, BellSouth recognizes that the Commission expressed some concern with including residential UNE-Ls. BellSouth noted that, notwithstanding its disagreement with the Commission's ruling, BellSouth takes seriously its obligations to abide by effective orders and is compelled to seek reconsideration to ensure that the Commission understands that implementing its *Change of Law Order* has practical ramifications.

Finally, BellSouth requested reconsideration because, from an operational perspective, CLP UNE-L lines are business lines. BellSouth noted that this is because the CLP is BellSouth's customer in a UNE serving arrangement. BellSouth maintained that while a CLP may elect to use a UNE loop to serve a residential end-user, there is nothing troublesome in considering all UNE loops business lines.

INITIAL COMMENTS

COMPSOUTH: CompSouth stated in its initial comments that BellSouth maintained that the Commission wrongfully concluded that when counting "Business Lines" as defined by the FCC, BellSouth should count only those switched access business lines that are actually being used to serve business customers and that BellSouth should not expand its count to include the number of switched business *and residential* access lines that BellSouth has the *capacity* to provide. CompSouth noted that BellSouth claimed that the Commission's decision is inconsistent with the FCC's directives on how to count business lines. Yet, CompSouth maintained, in its *Change of Law Order*, the Commission clearly noted that it had read and analyzed the FCC's directives in both the FCC's *TRRO* and Rule 51.5 and concluded that the FCC did not intend for an ILEC's business line count to be adjusted to reflect the maximum potential use. Therefore, CompSouth asserted that the Commission concluded that when counting business lines, BellSouth should count only those switched access lines that are used to serve a business customer.

CompSouth noted that BellSouth continues to assert that the Business Line rule should be applied only selectively. CompSouth stated that, according to BellSouth, the Commission may ignore the FCC's specific direction in Rule 51.5 that Business Lines "shall include only those access lines connecting end-user customers with incumbent LEC end-offices *for switched services*." CompSouth asserted that the methodology proposed by BellSouth, and properly rejected by the Commission, makes no effort to limit the Business Line count to access lines used to offer switched services. CompSouth maintained that there is no support in the *TRRO* or FCC Rules for BellSouth's claim that "full system capacity of BellSouth's switched access lines and CLP high-capacity loops must be used" in counting Business Lines. CompSouth stated that, in fact, as the Commission found it its

Change of Law Order, the exact opposite is true: the FCC explicitly limited Business Lines to access lines (whether served by BellSouth or CLPs) connecting end-users for switched services.

CompSouth argued that BellSouth's attempt to analogize its flawed position to newlyweds buying a new home does nothing to advance its flawed legal position. CompSouth maintained that BellSouth noted that when a CLP buys a DS1 loop, there may be unused capacity on the loop. CompSouth asserted that the FCC certainly understood this as well, and it found that only lines used to provide switched services should be counted as Business Lines. Moreover, CompSouth maintained that the FCC surely understood that some circuits on a DS1 loop may be dedicated to nonswitched data services. CompSouth asserted that the Business Line definition specifically excludes those nonswitched lines from the Business Line count. Thus, CompSouth argued, even if a CLP "grows into" full usage of a DS1 loop, the FCC specified that only the lines used to provide switched services to business customers count as Business Lines for purposes of the *TRRO* impairment criteria.

CompSouth maintained that the Commission should similarly reject BellSouth's contention that residential UNE-L lines should be included in the Business Line count. CompSouth noted that the FCC's Business Line definition in Rule 51.5 plainly states: "A business line is an incumbent LEC-owned switched access line *used to serve a business customer*, whether by the incumbent LEC itself or by a competitive LEC that leases the line from the incumbent LEC." CompSouth stated that lines used to serve residential customers are, by definition, not lines used to serve business customers. CompSouth asserted that to include residential UNE-L lines ignores the FCC's definition by ignoring the limitation regarding switched services. CompSouth noted that, in its Motion, BellSouth puts a new spin on its argument, asserting that *all* UNE-L lines are business lines because they are provided at wholesale to CLPs, and all CLPs are business customers. CompSouth asserted that this position is directly contrary to the FCC's Rule. CompSouth stated that the sentence quoted above makes clear that all ILEC lines used to serve business customers are to be counted, whether the business customer is served by the ILEC or by a CLP leasing the line from an ILEC. CompSouth asserted that there is no question that the business customer the FCC has in mind is a retail business customer, not a CLP purchasing UNEs from the ILEC at wholesale.

CompSouth argued that BellSouth also incorrectly claims that the Commission's decision on counting residential UNE-L is contrary to the record. CompSouth stated that BellSouth correctly noted that CompSouth witness Gillian understood that eliminating residential UNE-L lines from BellSouth's Business Line count would not have nearly the same impact as eliminating BellSouth's inflation of Business Lines resulting from counting non-switched access lines. CompSouth maintained that the fact that the impact of BellSouth's error of counting residential UNE-L is relatively small does not mean that BellSouth should thus be given an exemption from complying with the terms of the *TRRO*. Moreover, CompSouth noted, the Commission's correct legal determination that this error should be corrected is not in any way contrary to the factual record in this proceeding.

CompSouth maintained that, on the other hand, BellSouth's arguments about the "practicability" of implementing the Commission's decision are indeed contrary to the record. CompSouth noted that witness Gillian presented an administratively simple methodology – all based on data in BellSouth's possession – for implementing the Business Line count in a way that fully complies with the FCC's directives. CompSouth stated that, for example, CompSouth proposed that BellSouth use the percentage of residential UNE-L lines reported for the *Survey of Local Telecommunications Competition in North Carolina* published in October 2004. CompSouth noted that the Commission's decision to apply the *TRRO* as written need not be revisited for reasons of administrative convenience. CompSouth stated that it presented a methodology that implements all (not just selected) parts of the Business Line definition that is both practicable and accurate.

Finally, CompSouth noted that BellSouth cited to a fragment from a FCC Brief to the D.C. Circuit Court in an attempt to bolster its position on the Business Line definition. CompSouth maintained that in the cited portion of the Brief, however, the FCC itself notes that the question of proper application of the *TRRO* Business Line definition is "not before the Court." Thus, CompSouth argued that the relevance of this excerpt is questionable. CompSouth asserted that, more fundamentally, however, what the FCC said in its Brief is nothing more than a restatement of the terms of the Rule itself. CompSouth maintained that according to the FCC: "The [FCC]'s test requires ILECs to count business lines on a voice grade basis. In other words, a DS1 loop counts as 24 business lines, not one." CompSouth stated that it does not dispute that if a DS1 loop includes 24 business lines (*i.e.*, switched access lines used to provide service to a business customer), then the DS1 loop should be counted as 24 business lines for impairment purposes. CompSouth maintained that that does not mean that all of the capacity on a DS1 loop – no matter how it is used or whom it is used to serve – satisfies the criteria for being counted as a Business Line. CompSouth argued that the Commission's decision in this proceeding correctly reflects this understanding, and nothing the FCC has said in the *TRRO* or since its issuance is contrary to the Commission's holding in this case.

PUBLIC STAFF: The Public Staff stated in its initial comments that BellSouth argued in its Motion that the Commission's decision to preclude BellSouth from using full system capacity in determining its total number of switched access business lines and UNE-L lines provided to CLPs is inconsistent with the FCC's directives. The Public Staff noted that, in support of its argument, BellSouth pointed out that the Florida, Georgia, and South Carolina Public Service Commissions concluded that business lines should be calculated so as to recognize the maximum capacity to serve customers.

The Public Staff noted that, as further support for its request for reconsideration, BellSouth stated that it is unable to determine which UNE-L loops are residential because its records do not indicate whether a UNE-L loop is being used to provide business service or residential service. The Public Staff stated that, furthermore, BellSouth noted, CompSouth witness Gillan testified in his deposition that it would not be worth correcting BellSouth's business line count to exclude residential DS0 loops. The Public Staff stated that, finally, BellSouth argued that all CLP UNE-L lines are properly classified as business lines, because BellSouth's customer for these loops is the CLP, a business customer, even if the CLP's end-user customer is residential.

The Public Staff asserted that many of the arguments now being raised by BellSouth were included in the post-hearing brief and submissions of additional authority filed by BellSouth prior to the issuance of the Commission's *Change of Law Order*. For example, the Public Staff commented, BellSouth's argument that the Commission's decision is inconsistent with the FCC's Rules is nothing more than a restatement of its previously articulated position in this proceeding. The Public Staff asserted that BellSouth also pointed out in its post-hearing brief and submissions of additional authority that some states have reached a different conclusion regarding this issue. However, the Public Staff argued that it is clear from the *Change of Law Order* that the Commission devoted a considerable amount of time examining the FCC's intent and Rules. The Public Staff asserted that just because the Commission's decision is different from the one advocated by BellSouth does not mean that the Commission's decision violates FCC Rules.

The Public Staff noted that, as further support for its position regarding maximum capacity, BellSouth included, as Exhibit A to its Motion, an excerpt from the appellate Brief filed by the FCC in *Covad Communications Co. v. FCC*, No. 05-1095, an appeal currently pending in the United States Court of Appeals, District of Columbia Circuit. The Public Staff noted that, in that Brief, the FCC indicated that a DS1 line corresponded to 24 64 kbps-equivalents or 24 business lines. However, the Public Staff stated, in the same paragraph of its Brief, that the FCC explained that a petition for reconsideration is currently pending before the FCC regarding this very issue.

The Public Staff maintained that, as the voluminous discussion in *the Change of Law Order* attests, the issue of counting business lines is one of interpretation. The Public Staff noted that BellSouth has one interpretation of the FCC's Rules while the Commission has another. The Public Staff opined that, because this issue is currently under review by the FCC, the Public Staff believes it would be a futile undertaking to re-examine the issue now. Instead, the Public Staff recommended that the Commission should defer its decision pending the petition for reconsideration currently before the FCC. The Public Staff maintained that, if the FCC authoritatively states that the full capacity of high-capacity lines must be taken into account, the Commission can modify its *Change of Law Order* accordingly.

REPLY COMMENTS

BELLSOUTH: BellSouth stated in its reply comments that, since neither CompSouth nor the Public Staff had raised any new issues in their latest filings, it was not necessary for BellSouth to reply. BellSouth requested the Commission grant its Motion for Reconsideration and Clarification.

DISCUSSION

First, BellSouth believes that the Commission's decision to disallow the inclusion of full system capacity of BellSouth's switched access lines and CLP UNE-L lines is not consistent with the FCC's directives. BellSouth asserted that the FCC has made it clear that a DS1 line corresponds to 24 64kbps-equivalents, and therefore to 24 business lines. However, the Commission has considered this same argument before it issued its *Change of Law Order* and has rejected it. BellSouth has not provided any new or compelling arguments in this regard.

Specifically, the Commission believes that FCC Rule 51.5 must be read <u>as a whole</u>, and that, therefore, a business line should be counted <u>only</u> when it is <u>used to serve</u> a business customer. FCC Rule 51.5 states:

> <u>Business line</u>. A business line is an incumbent LEC-owned switched access line used to serve a business customer, whether by the incumbent LEC itself or by a competitive LEC that leases the line from the incumbent LEC. The number of business lines in a wire center shall equal the sum of all incumbent LEC business switched access lines, plus the sum of all UNE loops connected to that wire center, including UNE loops provisioned in combination with other unbundled elements. Among these requirements, business line tallies (1) shall include only those access lines connecting end-user customers with incumbent LEC end-offices for switched services, (2) shall not include non-switched special access lines, (3) shall account for ISDN and other digital access lines by counting each 64 kbps-equivalent as one line. For example, a DS1 line corresponds to 24 64 kbps-equivalents, and therefore to 24 'business lines.'

The Commission continues to believe that the first sentence of Rule 51.5 is the core of the FCC's definition of a business line. In addition, the Commission notes that the third sentence states, again, that among the requirements for a line to be counted as a business line for impairment purposes, that line shall connect end-user customers with ILEC end-offices for switched services. The Commission continues to believe that counting full system capacity would not be in compliance with the first sentence or third sentence of FCC Rule 51.5, which reference lines used to serve a customer and lines connecting end-user customers with ILEC end-offices for purposes of providing switched services. These directives do not indicate that full system capacity should be used to count business lines.

BellSouth also noted that it believes that the FCC's intent to use full system capacity was reiterated in the FCC's Brief filed in the United States Court of Appeals, District of Columbia Circuit. In its September 9, 2005 Brief, the FCC stated that "[t]he Commission's [FCC's] test requires ILECs to count business lines on a voice grade equivalent basis. In other words, a DS1 loop counts as 24 business lines, not one." The Commission agrees with CompSouth that what the FCC stated in its Brief is nothing more than a restatement of the terms of Rule 51.5 itself. The Commission also agrees with CompSouth that the quote from the FCC's Brief and Rule does not mean that all of the capacity on a DS1 loop satisfies the criteria for being counted as a business line. The Commission agrees with CompSouth that if a DS1 loop includes 24 switched access lines used to provide service to a business customer, then the DS1 loop should be counted as 24 business lines for impairment purposes. The Commission also notes, as did the Public Staff, that in the same referenced paragraph of the FCC's Brief, the FCC noted that a petition for reconsideration on this issue is pending before the FCC[1].

Second, BellSouth requested that the Commission reconsider its decision to disallow BellSouth's proposal to count residential UNE-L lines as business lines. BellSouth outlined three reasons for requesting reconsideration of this aspect of the *Change of Law Order*, as follows:

(a) the ruling is inconsistent with the evidentiary record;

(b) BellSouth cannot practicably implement this aspect of the ruling; and

(c) BellSouth's customer of record for the UNE-L, the CLP, is a business customer.

Addressing the first reason, that the ruling is inconsistent with the evidentiary record, the Commission agrees with CompSouth that the Commission's decision to exclude residential UNE-L lines from the count of business lines is not in any way contrary to the factual record in this proceeding. As BellSouth noted, CompSouth witness Gillan did state in his deposition that it would not be worth correcting the business line count to remove residential UNE-L lines because the number would be so small. However, witness Gillan did not agree that it is correct to include residential UNE-L lines in the business line count. Witness Gillan specifically stated in his deposition, as follows:

Q. DS0. You said this column does not include DS0.

[1] On March 28, 2005, several CLPs, including Birch Telecom, Inc., BridgeCom International, Inc., Broadview Networks, Eschelon Telecom, Inc., NuVox Communications, Inc., SNiP LiNK, LLC, XO Communications, Inc., and Xspedius Communications, Inc. filed a Petition for Reconsideration with the FCC in WC Docket No. 04-313. The petitioning CLPs asked for the FCC to reconsider its business line count rules concerning counting DS1 loops and other digital lines on a per 64 kbps-equivalent basis.

A. No. It probably over counts, because you can't be certain that they're used to provide switch business line services, but I did not make an adjustment to that line; that column is so inconsequential, I don't think it makes any difference.

Q. So when BellSouth counts business lines, you do not – you don't take issue with BellSouth including all DS0 UNE loops?

A. I think it's more accurate to say that it's such a small number, that trying to go in to do it correctly wouldn't be worth it. 'Cause you just – you don't know whether or not those lines are used to provide switch business line service. But there [are] so few of them, I did not try and correct for any potential error in that column.[1]

However, the Commission based its decision on FCC Rule 51.5, which specifies that a counted business line should be used to serve a business customer. Therefore, the Commission does not believe that its finding regarding residential UNE-L lines is inconsistent with the evidentiary record.

Next, BellSouth asserted that it cannot practicably implement the Commission's decision in this regard since BellSouth's records do not contain any class of service indicators for UNE-L lines. CompSouth argued that the Commission's decision does not need to be revisited for reasons of administrative convenience. CompSouth stated that it had proposed that BellSouth use the percentages of residential UNE-L lines reported for the *Survey of Local Telecommunications Competition in North Carolina* published in October 2004. The Public Staff did not specifically address BellSouth's assertion in this regard.

The Commission does not believe that BellSouth's assertion concerning the practicability of implementing the Commission's decision on residential UNE-L lines is persuasive. The Commission believes that BellSouth should use whatever methods it deems reasonable to identify or estimate the number of residential UNE-L lines and exclude those lines from its business line count. Residential UNE-L lines do not serve business customers and should not be included in the business line count in accordance with FCC Rule 51.5.

Finally, BellSouth maintained that BellSouth's customer of record for the UNE-L, the CLP, is a business customer; therefore, CLP UNE-L lines are business lines. The Commission believes that BellSouth's argument in this regard is without merit. The Commission agrees with CompSouth that the first sentence of FCC Rule 51.5 specifically states that a business line is an ILEC-owned switched access line used to serve a business customer, whether by the ILEC itself or by a CLP that leases the line from the ILEC. The business customer, therefore, is a retail business customer and not a CLP customer leasing a UNE-L from the ILEC.

Therefore, based upon the foregoing, the Commission finds it appropriate to deny BellSouth's Motion for Reconsideration on Finding of Fact No. 5. The Commission specifically notes that a Motion for Reconsideration on the correct method of counting business lines is pending before the FCC. The Commission notes that a future decision of the FCC may clarify that full system capacity should be used in counting business lines, and, in that event, BellSouth could seek authorization to alter its method of counting business lines in North Carolina to reflect full system capacity.

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[1] See Joint Exhibit No. 4, Gillan Deposition, Page 43.

CONCLUSIONS

The Commission finds it appropriate to deny BellSouth's Motion for Reconsideration and Clarification of Finding of Fact No. 5, thereby upholding and affirming its original decision in this regard.

FINDING OF FACT NO. 13 (ISSUE NO. 13 – MATRIX ITEM NO. 14): *TRO*/COMMINGLING – What is the scope of commingling allowed under the FCC's rules and orders and what language should be included in Interconnection Agreements (ICAs) to implement commingling (including rates)?

INITIAL COMMISSION DECISION

The Commission concluded that Section 271 offerings can be commingled with Section 251 UNE offerings. The cost of multiplexing equipment should be based on the cost of the higher speed element associated with the multiplexing equipment. Rates for commingling should remain at total element long-run incremental cost (TELRIC) prices for Section 251 UNEs and just and reasonable market prices for Section 271 elements.

MOTION FOR RECONSIDERATION

BELLSOUTH: BellSouth objected to Finding of Fact No. 13 and requested that the Commission reconsider its decision concerning commingling to ensure that the *Change of Law Order* as a whole is consistent concerning Section 271.

BellSouth stated that the Commission properly recognized that it does not have the authority to require BellSouth to include Section 271 elements in ICAs entered into pursuant to Section 252, nor does the Commission have the authority to set rates for such elements. The Commission had nevertheless concluded that Section 271 offerings can be commingled with Section 251 UNE offerings. Rates for commingling will remain at TELRIC prices for Section 251 UNEs and just and reasonable prices for Section 271 elements. The *TRRO* Amendments should reflect the Commission's conclusions on this issue. BellSouth requested reconsideration of this specific language.

BellSouth maintained that the Commission's commingling conclusions conflict with its Section 271 findings. In particular, by explicitly requiring BellSouth's contract amendments to reflect the Commission's conclusions, the Commission is intruding on the FCC's role of administering and enforcing Section 271, which it should not do. BellSouth argued that the Commission can remedy this aspect of its order as the Kansas Commission did; namely, by ruling that Section 271 commingling terms and conditions have no home in ICAs because the Commission would have no enforcement authority concerning commingling disputes. Alternatively, BellSouth stated that the Commission can require the inclusion of the commingling definition as set forth in the federal rules, without mandating explicit language concerning Section 271.

BellSouth argued that whether or not Section 271 services are wholesale services is not the controlling consideration. Thus, while the *Change of Law Order* focuses on whether Section 271 elements are wholesale services, BellSouth argued that reconsideration is appropriate because the FCC has very clearly created a Section 271 exception to any commingling obligation that exists. BellSouth stated that the Commission can remedy this aspect of its decision on reconsideration by making clear that BellSouth is required to commingle or to allow commingling of a UNE or a UNE combination with one or more facilities or services that a CLP has obtained at wholesale from an ILEC pursuant to any method other than unbundling under Section 251(c)(3), except for offerings made available under Section 271. BellSouth stated that this approach would appropriately focus on the Section 271 exclusion to any commingling obligations and would bring the Commission into accord with several other state commissions regarding this issue.

INITIAL COMMENTS

COMPSOUTH: CompSouth noted that BellSouth does not articulate any new argument in support of its request. Instead, BellSouth urged the exclusion under the guise that exclusion of any reference to Section 271 terms and conditions is merited to ensure that the *Change of Law Order* as a whole is consistent concerning Section 271.

Contrary to BellSouth's assertion, CompSouth argued that the Commission's conclusions on the issue of Section 271 commingling are not inconsistent with any other finding of the Commission. CompSouth observed that, in its *Change of Law Order*, the Commission derived the commingling obligation of Section 251(c)(3) UNEs with Section 271 elements not from Section 271 but from Section 252(c)(1), which requires state commissions to ensure that ICAs meet the requirements of Section 251. Therefore, ICAs must meet the requirements of the FCC's rules addressing commingling and allow commingling of Section 251 elements with Section 271 elements. Thus, CompSouth stated that the Commission's directive that ICAs meet the requirements of commingling contemplated by the FCC is necessary to effectuate the requirements set down by the FCC. CompSouth argued that the Commission correctly held that the FCC has required commingling to be available for any wholesale service, and that category includes offerings made available pursuant to BellSouth's Section 271 obligations whether those obligations are spelled out in the ICA or not.

The Commission has exhaustively examined this issue. A thorough examination has occurred in both this proceeding and in a separate arbitration docket. CompSouth argued that the Commission reached the correct conclusion and should therefore deny BellSouth's request for reconsideration.

PUBLIC STAFF: The Public Staff noted that, in Finding of Fact No. 13, the Commission stated that offerings made pursuant to Section 271 of the Telecommunications Act of 1996 (TA96 or the Act) may be commingled with Section 251 UNE offerings. The Public Staff stated that this finding on commingling is consistent with the Commission's previous conclusion on this issue in the *Order Ruling on Objections and Requiring the Filing of the Composite Agreement,* Docket No. P-772, Sub 8, *et al.*

The Public Staff argued that BellSouth's motion for reconsideration regarding Finding of Fact No. 13 should be denied. The Commission has thoroughly considered this issue in Docket No. P-772, Sub 8, *et al.*, as well as in the instant docket. The Public Staff commented that the Commission rejected BellSouth's claim that the Commission lacks authority to require that ICAs reflect BellSouth's commingling obligations. The Public Staff argued that the Commission properly found instead that its authority to require commingling stems not from Section 271, but from Section 252(c)(1) of the Act, which requires state commissions to ensure that ICAs meet the requirements of Section 251. The Public Staff stated that BellSouth has offered no new or persuasive argument for a reversal of the Commission's decision here.

There is no compelling reason for the Commission to revisit its decision that the FCC has not excluded Section 271 elements from commingling obligations. The Public Staff stated that BellSouth's citation to *United States Telecom Association v. FCC*, 359 F.3d 554, 589 (D.C. Cir. 2004) (*USTA II*), is inapposite, because it discusses an ILEC's duty to combine network elements. As the Commission has properly recognized, commingling is not the same as combining, and BellSouth provides no reason to revisit that distinction.

Finally, the Public Staff noted BellSouth's argument that it would be in accord with the decision of other state commissions if it found in BellSouth's favor on reconsideration. It is true that this issue has been contested in other states with various outcomes. The Public Staff argued that the fact that other states may have decided this issue differently does not undermine the Commission's decision here. Instead, the Public Staff stated that the Commission's conclusions on Finding of Fact No. 13 are sound and should be affirmed.

REPLY COMMENTS

BELLSOUTH: BellSouth stated in its reply comments that, since neither CompSouth nor the Public Staff had raised any new issues in their latest filings, it was not necessary for BellSouth to reply. BellSouth requested the Commission grant its Motion for Reconsideration and Clarification.

DISCUSSION

After careful consideration, the Commission concludes that BellSouth's Motion for Reconsideration as to this issue should be denied. The essential argument that BellSouth has made—and that it made from the beginning—is that commingling should not include Section 271 elements and that allowing them to be commingled with Section 251 elements contradicts the Commission's decision in Issue No. 8. On the contrary, the Commission in its original *Change of Law Order* carefully distinguished between its conclusion in Issue No. 8 that Section 271 elements should not be included in ICAs and its conclusion in Issue No. 13 regarding commingling. In a nutshell, commingling constitutes a special situation because Section 271 elements constitute "wholesale" elements, and the FCC held that "wholesale" elements should be commingled with other elements. The basis for commingling, moreover, derives from Section 251, not Section 271. The Commission has heard no arguments from BellSouth on reconsideration which are not essentially repetitive of the arguments it has heretofore made and which have been rejected. The Commission is therefore not persuaded that it should reconsider its original conclusion on this issue.

CONCLUSIONS

The Commission finds it appropriate to deny BellSouth's Motion for Reconsideration and Clarification of Finding of Fact No. 13, thereby upholding and affirming its original decision in this regard.

<u>FINDING OF FACT NO. 15 (ISSUE NO. 15 – MATRIX ITEM NO. 16)</u>: *TRO* / CONVERSIONS – What are the appropriate rates, terms, and conditions, and effective dates, if any, for conversion requests that were pending on the effective date of the *TRO*?

INITIAL COMMISSION DECISION

The Commission concluded that the rates, terms, and conditions for conversions should be retroactive back to the *TRO* effective date, except that requests for conversions that were pending as of the effective date of the *TRO* should be processed under the conditions that existed prior to the *TRO*.

MOTION FOR RECONSIDERATION

BELLSOUTH: BellSouth objected to Finding of Fact No. 15, stating that the Commission's decision to mandate conversion rights retroactive to October 2, 2003, cannot be reconciled with the evidentiary record because it improperly provides CLPs that failed to negotiate *TRO* amendments an unfair advantage over other CLPs and because it conflicts with the FCC's directives.

BellSouth maintained that the Commission's ruling on this issue is inconsistent with the evidence. BellSouth commented that CompSouth's witness did not request or testify that conversion requests that were made after the effective date of the *TRO* should be retroactive to October 2, 2003. BellSouth argued that CompSouth's testimony requested conversion rights retroactive to March 11, 2005 (the effective date of the *TRRO*), and not October 2, 2003.[1] BellSouth opined that there is no reason to provide CLPs with a windfall that exceeds their requested contract language. Moreover, BellSouth asserted that no CLP could legitimately object to reconsideration in order to ensure that the Commission's *Change of Law Order* conforms to the evidentiary record.

In addition, BellSouth argued that the Commission's decision provides an unfair advantage to CLPs that failed to amend their agreements as compared to other CLPs. BellSouth explained that this is because many CLPs did amend their interconnection agreements to include conversion rights at various times following the *TRO*; and every CLP that signed such an amendment became entitled to convert standalone special access circuits to UNEs following execution of the amendment to include the conversion language – and not at some earlier time. BellSouth contended that the Commission's ruling sends the wrong message in that delays in resolving contract disputes have been rewarded by retroactive contractual rights that exceed the contractual rights of other CLPs.

Lastly, BellSouth argued that the Commission's ruling in this regard is also at odds with the FCC's directives because, in the *TRO*, the FCC adopted new criteria CLPs must meet to convert special access circuits to UNEs.[2] In particular, BellSouth observed that the FCC specifically required carriers to use the negotiation and amendment process to implement the new obligations in the *TRO*, and rejected arguments to override the Section 252 process and unilaterally change all interconnection agreements.[3] BellSouth asserted that the FCC made clear that, as to the *TRO*, individual carriers should be allowed to negotiate specific terms and conditions to translate the new

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[1] *See First Revised Exhibit JPG-1*, Pages 2, 4, 6, 8, 11, and 13 ("to the extent that language implementing . . . conversion . . . rights/obligations is effective retroactively to March 11, 2005, BellSouth may apply transition rates retroactively to March 11, 2005 as well.")

[2] See *TRO* at Paragraph 577.

[3] See *TRO* at Paragraph 702.

rules into the commercial environment.[1] BellSouth observed that several state commissions confronted by this identical issue have ruled in a manner contrary to this Commission's ruling[2]; those commissions determined that the FCC intended to allow conversion rights beginning on the date that interconnection agreements were amended and not going back to October 2, 2003. BellSouth maintained that the Commission should reconsider its *Change of Law Order* in this regard and reach a similar result.

INITIAL COMMENTS

COMPSOUTH: CompSouth asserted in its initial comments that the Commission fully examined this issue and that the Commission's determination that conversion rights should be retroactive to the effective date of the *TRO* is reasonable and not inconsistent with any FCC directive.[3]

With respect to BellSouth's argument that reconsideration is warranted because CompSouth's witness did not expressly request or testify that conversion requests made after the effective date of the *TRO* should be retroactive to the effective date of the *TRO*, CompSouth observed that the Commission noted such fact in its *Change of Law Order*, but observed that CompSouth, in its Brief, asserted that the rates, terms, and conditions for conversions pending on the effective date of the *TRO* should be those that reflect the FCC's decisions in the *TRO*. In addition, CompSouth stated that the Commission noted that CompSouth pointed out that, in the *TRO*, the FCC expressly addressed the question of how to handle pending conversion requests when it issued the *TRO* and that, in such instance, the FCC tied pricing provisions regarding conversions to the effective date of the *TRO*. Thus, CompSouth urged the Commission to use the effective date of the *TRO* as the effective date for conversions in the amended interconnection agreements. CompSouth asserted that the question is essentially a legal one, and the FCC addressed it explicitly in the *TRO*. CompSouth maintained that the Commission's determination is supported by the *TRO* and was properly raised and briefed by CompSouth.

Next, regarding BellSouth's argument that the Commission's ruling unfairly advantages those CLPs that failed to amend their interconnection agreements, CompSouth observed that BellSouth has not provided any support for this "unfair advantage" argument or why it should trump the directive of the FCC or generally adopted true-up concepts.

Finally, CompSouth stated that BellSouth has claimed that the Commission's ruling is at odds with the FCC's general directives in the *TRO* and, specifically, BellSouth has generally postulated that by establishing the effective date of the *TRO* as the effective date for conversions, the Commission has

[1] See *TRO* at Paragraphs 700-704. BellSouth argued that the FCC's directive in the *TRO* differed from its mandate in the *TRRO*, in which the FCC made its nationwide bar on new UNE-P arrangements and other delisted elements effective on March 11, 2005, without the need for amendments to interconnection agreements.

[2] *See* Florida Docket No. 041269-TP, Order No. PSC-06-0172-FOF-TP, *Order Addressing Changes of Law;* No. 2006-136, South Carolina Docket No. 2004-316-C, *2005 D.C. PUC LEXIS 257; Arbitration Order,* Massachusetts D.T.E. 04-33, (July 14, 2005); *Arbitration Decision,* Rhode Island Docket No. 3588, (November 10, 2005); and New Jersey Docket Nos. TO05050418 *et al, Telecommunications Order* (March 27, 2006).

[3] CompSouth also noted that the Commission's ruling is consistent with the recent ruling of the Georgia Public Service Commission. "The Commission finds consistent with CompSouth's position that CLECs that submitted legitimate requests to convert wholesale services to UNEs or UNE combinations prior to the effective date of the *TRO* are entitled to UNE pricing as of the date the *TRO* became effective."

impliedly run afoul of the new negotiation and amendment process adopted by the FCC in the *TRO* that allows carriers to negotiate the specific terms and conditions of their agreements. CompSouth contended that BellSouth cannot and does not, however, point to any specific language in the *TRO* or any other pronouncement by the FCC to support its belief. Indeed, CompSouth asserted that is because there is none.

CompSouth maintained that the Commission's decision is completely consistent with the FCC's directive in the *TRO*. CompSouth opined that, since the conversion rights were established when the *TRO* took effect, it is reasonable and correct that the effective dates for the mandated conversion rights to be effective should be the date the *TRO* became effective. Accordingly, CompSouth argued that the Commission should not reconsider its ruling on this issue.

PUBLIC STAFF: The Public Staff stated in its initial comments that BellSouth objected to the Commission's Finding of Fact No. 15, which states that "[t]he rates, terms, and conditions for conversions should be retroactive back to the *TRO* effective date [October 2, 2003], except that requests for conversions that were pending as of the effective date of the *TRO* should be processed under the conditions that existed prior to the *TRO*." The Public Staff noted that BellSouth requested reconsideration of the ruling for three reasons: (1) the ruling is contrary to the evidentiary record; (2) the ruling improperly provides CLPs that failed to negotiate *TRO* amendments an unfair advantage over other CLPs; and (3) the ruling conflicts with the FCC's directives. The Public Staff maintained that none of BellSouth's allegations, however, require the Commission to reconsider its conclusions for Finding of Fact No. 15.

The Public Staff noted that BellSouth first contended that the Commission's finding is inconsistent with the evidence because CompSouth's witness did not request or testify that conversion requests that were made after the effective date of the *TRO* should be retroactive to October 2, 2003. The Public Staff asserted that, rather, according to BellSouth, CompSouth's testimony requested conversion rights retroactive to March 11, 2005, the effective date of the *TRRO*, and not October 2, 2003. The Public Staff noted that BellSouth believes that the Commission's ruling provides the CLPs with an undeserved windfall in that it exceeds the CLPs' requested contract proposal.

The Public Staff observed that it had argued in its proposed order that, when deciding differences between parties in an arbitration dispute, the Commission has generally adopted the concept of true-ups, i.e., rates or terms and conditions become effective when the regulatory body, either the Commission or the FCC, approves the change.[1] The Public Staff stated that it believed neither party presented an adequate resolution to this issue in this docket. Therefore, the Public Staff noted that it had recommended that the Commission adopt the "true-up" rationale that the rates, terms, conditions, and effective dates for conversions in the amended ICA be retroactive to the *TRO* effective date in fairness to all the parties.

Further, the Public Staff asserted that, because of actions taken by the FCC in the *TRRO*, the proposed transition rates included in CompSouth witness Gillan's Exhibit JPG-1 required modification. Therefore, the Public Staff noted, witness Gillan added the language in his proposed Section 2.3.6.3 to apply to rates during the transition period specified in the *TRRO* for those dark fiber UNE loops being transitioned from Section 251 UNEs. The Public Staff maintained that, had

[1] *See Change of Law Order*, Page 124.

he not done so, the ICA would not be reflective of the changes mandated by the FCC in the *TRRO*. The Public Staff argued that a simple reading of witness Gillan's proposed Section 2.3.6.3 shows that the language reflects the rates that are applicable during the transition period that began on March 11, 2005, when the *TRRO* became effective.

Furthermore, the Public Staff noted that witness Gillan also included this language in Section 2.2.6 concerning the transition rates applicable to certain DS1 and DS3 UNE loops, in Section 4.4.4 concerning the transition rates applicable to certain local switching UNEs, in Section 5.3.3.4 concerning the transition rate for UNE-P, in Section 6.2.4.4 concerning the transition rates for certain DS1 and DS3 dedicated transport UNEs, and in Section 6.9.1.5 concerning the transition rates for certain dark fiber UNE transport. The Public Staff maintained that these are all UNEs affected by the *TRRO,* and the ICA needs to reflect the transition period imposed by the *TRRO*. The Public Staff asserted that witness Gillan's language merely addresses this need.

In addition, the Public Staff maintained that BellSouth's argument also appears to be that the Commission was bound by final offer or "baseball" arbitration rules to accept either BellSouth's or CompSouth's proposal, with no consideration of other alternatives. The Public Staff stated that it believes, however, that the Commission had the flexibility to find and conclude as it did, based upon the Commission's review of the evidence and arguments presented by the parties.

The Public Staff argued that, moreover, the Commission's ruling does not, as BellSouth asserted, give an unfair advantage to CLPs that failed to amend their agreements as compared to other CLPs, since each CLP had the same opportunity to amend or not amend its agreement. The Public Staff maintained that amending agreements is the responsibility of all the parties involved. The Public Staff asserted that failure to amend an agreement cannot be blamed solely on a CLP; the CLPs that were able to amend their ICAs after the *TRO* were aware of its existence and should have taken it into consideration.

Finally, the Public Staff noted that the Commission's ruling is not at odds with the FCC's directives. The Public Staff maintained that simply because some other states have decided differently does not warrant revision of Finding of Fact No. 15. The Public Staff stated that Paragraph 589 of the *TRO,* which was cited by the Commission on Page 124 of its *Change of Law Order*, solidly supports the Commission's decision to make the rates, terms, and conditions retroactive to the effective date of the *TRO*. The Public Staff maintained that the Commission's conclusion on conversions pending on the effective date of the *TRO* is the position advocated by BellSouth and is consistent with FCC directives. The Public Staff noted that, also in compliance with FCC directives, the Commission's ruling does not negate any agreements between the parties. The Public Staff stated that the last phrase in Ordering Paragraph 2, Page 197, stated that "the parties may mutually agree on language that departs from the provisions of this Order." The Public Staff asserted that parties remain free to negotiate this issue and adopt language that differs from the Commission's conclusions. However, the Public Staff asserted that the Commission's conclusions and findings on this issue are sound and should be affirmed.

REPLY COMMENTS

BELLSOUTH: BellSouth stated in its reply comments that, since neither CompSouth nor the Public Staff had raised any new issues in their latest filings, it was not necessary for BellSouth to reply. BellSouth requested the Commission grant its Motion for Reconsideration and Clarification.

DISCUSSION

BellSouth is seeking reconsideration of the Commission's decision regarding conversion rights. BellSouth has presented three arguments in support of its request: (1) the ruling is inconsistent with the evidence; (2) the ruling provides an unfair advantage to CLPs that failed to amend their agreements as compared to other CLPs; and (3) the ruling is at odds with the FCC's directives.

First, BellSouth argued that the Commission's ruling in Finding of Fact No. 15 is inconsistent with the evidence. BellSouth maintained that CompSouth witness Gillan did not request or testify that conversion requests that were made after the effective date of the *TRO* should be retroactive to October 2, 2003. BellSouth asserted that CompSouth's testimony requested conversion rights retroactive to March 11, 2005 (the effective date of the *TRRO*), and not October 2, 2003. BellSouth specifically noted First Revised Exhibit JPG-1, Pages 2, 4, 6, 8, 11, and 13 and referenced the "to the extent that language implementing . . . conversion . . . rights/obligations is effective retroactively to March 11, 2005, BellSouth may apply transition rates retroactively to March 11, 2005 as well" language provided therein. However, the Commission has reviewed the noted Sections of First Revised Exhibit JPG-1, specifically Sections 2.2.6, 2.3.6.3, 4.4.4, 5.3.3.4, 6.2.4.4, and 6.9.1.5, and agrees with the Public Staff that witness Gillan's proposed language reflects the rates for UNEs affected by the *TRRO* that are applicable during the transition period that began on March 11, 2005, when the *TRRO* became effective.

In addition, the Commission agrees with CompSouth that, although CompSouth did not present any testimony in this regard, CompSouth did state in its Brief that the rates, terms, and conditions for conversions pending on the effective date of the *TRO* should be those that reflect the FCC's decisions in the *TRO*. Further, the Commission agrees with the Public Staff that the Commission has the flexibility to find and conclude that the rates, terms, and conditions for conversions should be retroactive back to the *TRO* effective date after a review of the evidence and arguments presented by the parties and a review of applicable FCC Orders. Therefore, the Commission does not believe that its ruling in Finding of Fact No. 15 is inconsistent with the evidence.

BellSouth's second argument is that the ruling in Finding of Fact No. 15 provides an unfair advantage to CLPs that failed to amend their agreements as compared to other CLPs. The Commission agrees with CompSouth that BellSouth has not offered any support for this argument or explained why this argument should undermine the directive of the FCC or the generally adopted true-up provision. In addition, as the Public Staff pointed out, each CLP had the same opportunity to amend or not amend its agreement, and amending agreements is the responsibility of all the parties involved. The fact of the matter is that the FCC adopted conversion rights which should be made allowable as of the effective date of the *TRO*. In Paragraph 589 of the *TRO*, the FCC explicitly states:

> As a final matter, we decline to require retroactive billing to any time before the effective date of this Order. The eligibility criteria we adopt in this Order supersede the safe harbors that applied to EEL conversions in the past. To the extent pending requests have not been converted, however, competitive LECs are entitled to the appropriate pricing up to the effective date of this Order. [Emphasis added.]

Therefore, the Commission does not find merit in BellSouth's argument that the Commission's ruling provides an unfair advantage to CLPs that failed to amend their agreements as compared to other CLPs.

BellSouth's final argument is that the Commission's ruling is at odds with the FCC's directives. However, the Commission agrees with CompSouth and the Public Staff that the Commission's ruling is not in any way in conflict with the directives of the FCC. As the Public Staff noted, Paragraph 589 of the *TRO*, as quoted above, solidly supports the Commission's decision in this regard. BellSouth has not provided any directives of the FCC which run counter to the Commission's decision. Therefore, the Commission does not believe that its decision on conversion rights is at odds with the FCC's directives.

Based upon the foregoing discussion, the Commission finds it appropriate to deny BellSouth's Motion for Reconsideration on Finding of Fact No. 15.

CONCLUSIONS

The Commission finds it appropriate to deny BellSouth's Motion for Reconsideration and Clarification of Finding of Fact No. 15, thereby upholding and affirming its original decision in this regard.

<u>FINDING OF FACT NO. 18 (ISSUE NO. 18 – MATRIX ITEM NO. 19)</u>: *TRO*/LINE SPLITTING – What is the appropriate ICA language to implement BellSouth's obligations with regard to line splitting?

INITIAL COMMISSION DECISION

The Commission concluded that:

(a) In accordance with the Commission's decision on Matrix Item No. 14, line splitting should be allowed on a commingled arrangement of a Section 251 loop and unbundled local switching pursuant to Section 271;

(b) BellSouth and CompSouth should negotiate acceptable language to address whether a CLP should indemnify BellSouth for "claims" or "claims and actions" arising out of actions by the other CLP involved in the line splitting arrangement;

(c) It is appropriate to adopt Section 3.8.15 from CompSouth's First Revised Exhibit JPG-1 concerning access to OSS; and

(d) BellSouth is not obligated to provide CLPs with access to BellSouth-owned splitters; however, CompSouth's proposed language in Section 3.6.13 of CompSouth's First Revised Exhibit JPG-1 is acceptable.

MOTION FOR RECONSIDERATION

BELLSOUTH: BellSouth requested that the Commission clarify its Conclusions for Finding of Fact No. 18 concerning line splitting. Specifically, BellSouth stated that it was looking to ensure that the

Commission is not seeking to regulate the operational manner in which line splitting will be provided. BellSouth maintained that for CLPs that purchase Section 271 switching from BellSouth together with a Section 251 loop, line splitting can and should be properly provided by allowing a CLP to terminate both the Section 271 switch port and the Section 251 loop in the collocation space of the data provider and allowing the voice CLP and the data CLP to cooperatively work together to connect the two services and provide line splitting. BellSouth argued that it should not be required to be in the middle of the relationship of a voice CLP and a data CLP, nor should BellSouth be required to perform the tasks necessary to effectuate line splitting over its commercial Section 271 offering.

BellSouth maintained that it seeks clarification to ensure that future disputes do not arise between it and other CLPs in which other CLPs may claim the *Change of Law Order* requires BellSouth to offer line splitting over its Section 271 switching offering. BellSouth noted that FCC Rule 47 C.F.R. 51.319(a)(1)(ii) requires BellSouth to "provide a requesting telecommunications carrier that obtains an unbundled copper loop from the incumbent LEC with the ability to engage in line splitting arrangements with another competitive LEC using a splitter collocated at the central office where the loop terminates into a distribution frame or its equivalent." BellSouth asserted that the federal rules are consistent with BellSouth's operational plans to provide line splitting. BellSouth argued that the Commission should not require BellSouth to effectuate line splitting over its Section 271 switching product – any such outcome would improperly intrude upon the FCC's exclusive Section 271 authority, and BellSouth is seeking reconsideration or clarification in an effort to avoid future disputes.

INITIAL COMMENTS

COMPSOUTH: CompSouth stated in its initial comments that BellSouth's proposed clarification would significantly undermine the Commission's decision on commingling. CompSouth asserted that, as "clarified" by BellSouth, anyone using BellSouth's commercial wholesale loop/switching product (what was known as UNE-P or the UNE platform) would be forced to switch the entire facility to a standalone loop to the data CLP's collocation space. CompSouth stated that, in turn, this approach would require a hot cut, cause a voice outage, and result in significant additional expense for the rearrangement. CompSouth asserted that the Commission should resist BellSouth's effort to effectively deny commingling for a particular wholesale service – line splitting. CompSouth argued that the commingling obligation is not an obligation that exists for all wholesale services "except one." CompSouth opined that commingling is an obligation for *all* wholesale services. CompSouth maintained that BellSouth's commercial platform service is a wholesale service – one that BellSouth must commingle with other wholesale services. CompSouth asserted that BellSouth's effort to avoid this obligation for the most competitively important arrangement of the commingled wholesale services — a bundle of data and voice (line splitting) — is directly contrary to the FCC's effort to encourage bundled products. CompSouth maintained that BellSouth should continue to provide line splitting as it always has – adding line splitting to the wholesale platform product. CompSouth asserted that BellSouth's motion for clarification should be denied.

PUBLIC STAFF: The Public Staff stated in its initial comments that, in Finding of Fact No. 18, the Commission held that "line splitting should be allowed on a commingled arrangement of a Section 251 loop and unbundled local switching pursuant to Section 271." The Public Staff noted that BellSouth has requested clarification of this finding. The Public Staff maintained that BellSouth has contended that the Commission should not regulate the operational manner in which line splitting is provisioned over its Section 271 switching product, as this would improperly intrude on the FCC's exclusive authority over Section 271. The Public Staff noted that BellSouth maintained that line splitting can be established on a commingled arrangement through the cooperation of the voice CLP and the data CLP without involvement from BellSouth.

The Public Staff noted that, in the *Change of Law Order*, the Commission determined that when a CLP obtains a commingling arrangement consisting of switching under Section 271 and a UNE loop under Section 251, BellSouth must allow line splitting but is not obligated to provision BellSouth-owned splitters for use by CLPs. The Public Staff asserted that, based on these findings, it is not clear to the Public Staff why further clarification is needed. The Public Staff noted that BellSouth has acknowledged that it is responsible for ensuring that CLPs have the ability to engage in line splitting, and it appears from BellSouth's comments that it can satisfy both the Commission's findings and its current federal obligations. The Public Staff opined that, therefore, without further persuasive reasoning, the Public Staff does not believe that clarification or reconsideration of Finding of Fact No. 18 is necessary.

REPLY COMMENTS

BELLSOUTH: BellSouth stated in its reply comments that, since neither CompSouth nor the Public Staff had raised any new issues in their latest filings, it was not necessary for BellSouth to reply. BellSouth requested the Commission grant its Motion for Reconsideration and Clarification.

DISCUSSION

The Commission agrees with the Public Staff that it is not clear why further clarification is needed on this issue. In the *Change of Law Order*, the Commission ruled that BellSouth must <u>allow</u> line splitting on a commingled arrangement consisting of a Section 251 loop and Section 271 switching and that BellSouth is not obligated to provide CLPs with access to BellSouth-owned splitters. The Commission does not believe that BellSouth has provided any compelling or convincing arguments which warrant any clarification or reconsideration of Finding of Fact No. 18.

BellSouth stated that it is seeking to ensure that CLPs do not claim that the Commission's *Change of Law Order* requires BellSouth to offer line splitting over its Section 271 switching offering. The Commission believes that the *Change of Law Order* specifically finds that BellSouth must <u>allow</u> line splitting on a <u>Section 251 loop</u> which is included in a Section 251 loop/Section 271 switching commingled arrangement. The Commission does not believe that BellSouth has provided any arguments which warrant clarification or reconsideration of the Commission's conclusions in this regard. Therefore, the Commission finds it appropriate to deny BellSouth's motion for clarification of Finding of Fact No. 18, thereby upholding and affirming the Commission's original decision on this issue.

CONCLUSIONS

The Commission finds it appropriate to deny BellSouth's Motion for Reconsideration and Clarification of Finding of Fact No. 18, thereby upholding and affirming its original decision in this regard.

<u>**FINDING OF FACT NO. 20 (ISSUE NO. 20 – MATRIX ITEM NO. 23(b))**</u>: What is the appropriate language to implement BellSouth's obligation, if any, to offer unbundled access to

newly-deployed or "Greenfield" fiber loops, including fiber loops deployed to the minimum point of entry (MPOE) of a multiple dwelling unit that is predominantly residential and what, if any, impact does the ownership of the inside wiring from the MPOE to each end user have on this obligation?

INITIAL COMMISSION DECISION

The Commission concluded that the following sections should be incorporated into the *TRRO* amendments:

> 2.1.2 Fiber to the Home (FTTH) loops are local loops consisting entirely of fiber optic cable, whether dark or lit, serving an End User's premises or, in the case of predominantly residential multiple dwelling units (MDUs), a fiber optic cable, whether dark or lit, that extends to the MDU minimum point of entry (MPOE). Fiber to the Curb loops are local loops consisting of fiber optic cable connecting to a copper distribution plant that is not more than five hundred (500) feet from the End User's premises or, in the case of predominantly residential MDUs, not more than five hundred (500) feet from the MDU's MPOE. The fiber optic cable in a FTTC loop must connect to a copper distribution plant at a serving area interface from which every other copper distribution subloop also is not more than five hundred (500) feet from the respective End User's premises. BellSouth shall offer CLECs unbundled access to FTTH/FTTC loops serving enterprise customers and predominantly business MDUs.
>
> 2.1.2.1 In new build (Greenfield) areas, where BellSouth has only deployed FTTH/FTTC facilities, BellSouth is under no obligation to provide such FTTH and FTTC Loops. FTTH facilities include fiber loops deployed to the MPOE of a MDU that is predominantly residential regardless of the ownership of the inside wiring from the MPOE to each End User in the MDU.
>
> 2.1.2.3 Notwithstanding the above, nothing in this Section shall limit BellSouth's obligation to offer CLECs an unbundled DS1 loop (or loop/transport combination) in any wire center where BellSouth is required to provide unbundled access to DS1 loops and loop/transport combinations.

MOTION FOR RECONSIDERATION

BELLSOUTH: BellSouth objected to Finding of Fact No. 20 and requested that the Commission's decision be reconsidered or clarified to reflect incorporation of the following contract language for Section 2.1.2.3:

> In new build (Greenfield) areas, where BellSouth has only deployed FTTH/FTTC facilities, BellSouth is only required to unbundle DS1 loops to predominantly commercial MDUs, but has no obligation to unbundle such fiber loops to residential MDUs or any other end user customer premises. While the FCC's rules provide that FTTH/FTTC loops serving end user customer premises do not have to be unbundled, CLP access to unbundled DS1 loops at predominantly commercial MDUs is preserved. Accordingly, in wire centers in which a non-impairment finding for DS1

loops has not been made, BellSouth is obligated upon request to unbundle a FTTH/FTTC loop to provide a DS1 loop to a predominantly commercial MDU.

BellSouth maintained that its proposed language, included above, more fully addresses the scope of the FCC's fiber relief and makes clear that the FCC's fiber orders distinguish between predominantly commercial and residential MDUs. BellSouth asserted that the Commission recognized a distinction between predominantly business MDUs and predominately residential MDUs, yet the *Change of Law Order,* as written, allows widespread unbundling to predominantly residential MDUs. BellSouth contended that such unbundling conflicts with the FCC's *MDU Reconsideration Order.* Significantly, BellSouth explained that, if a CLP is provided a DS1 FTTH/FTTC loop to a predominantly residential MDU, a CLP could easily subdivide the loop to provide DS0 service to a residential customer and thereby thwart the FCC's fiber relief. BellSouth noted that, while BellSouth's original contract language, unmodified, remains appropriate, BellSouth is now requesting clarification to ensure that the *Change of Law Order* does not allow CLPs to circumvent the FCC's fiber orders.

INITIAL COMMENTS

COMPSOUTH: CompSouth stated in its initial comments that BellSouth's requested "clarification" would eviscerate the Commission's carefully considered decision on this issue. As the Commission noted, the FCC "intended for FTTC and FTTH loops to enterprise customers to be subject to loop unbundling obligations." As the evidence and arguments before the Commission made clear, that conclusion by the FCC was not limited by the FCC's holding regarding "predominantly residential" MDUs. According to CompSouth, the "clarification" proposed by BellSouth would eliminate loop unbundling obligations for enterprise customers in situations in which the FCC meant for such obligations to be maintained. The contract language adopted by the Commission preserves enterprise loop unbundling obligations as intended by the FCC, while also memorializing the substantial unbundling relief that BellSouth did receive in the FTTC/FTTH context. Therefore, CompSouth urged the Commission not to disturb that balance.

PUBLIC STAFF: The Public Staff stated in its initial comments that, in Finding of Fact No. 20, the Commission developed language to implement the *TRO*, the FCC's *MDU Order*, and its *FTTC Order,* which required ILECs to provide CLPs limited access to FTTH and FTTC loops and DS1 loops. The Commission incorporated three specific sections into the *TRRO* amendments to address these requirements. The Public Staff pointed out that, in Section 2.1.2, the Commission mirrored the FCC's definitions of FTTH and FTTC loops in 47 C.F.R. 51.319(a)(3) and established access requirements for loops serving enterprise customers and predominantly business MDUs. In Section 2.1.2.1, the Commission covered access requirements for FTTH and FTTC loops in new build (Greenfield) areas. In Section 2.1.2.3, the Commission adopted, with minor modifications, language proposed by CompSouth that addressed DS1 loop and transport unbundling in the context of the FCC's FTTH/FTTC access requirements.

The Public Staff stated that it continues to believe, based on its reexamination of the *TRO*, the *MDU Order*, the *FTTC Order*, and 47 C.F.R. 51.319(a), that the language adopted by the Commission for Sections 2.1.2, 2.1.2.1, and 2.1.2.3 faithfully implements the FCC's current policy defining an ILEC's obligation to provide CLPs with unbundled access to FTTH, FTTC, and DS1 loops. In Paragraph 325 of the *TRO*, the FCC found that "requesting carriers generally are impaired without access to unbundled DS1 loops." Footnote 956 to that finding emphasized that this access was in no way limited by the technology employed to provide it, or by the nature of the customers to be served:

> DS1 loops will be available to requesting carriers, without limitation, regardless of the technology used to provide such loops, *e.g.*, two-wire and four-wire HDSL or SHDSL, fiber optics, or radio, used by the incumbent LEC to provision such loops and regardless of the customer for which the requesting carrier will serve unless otherwise specifically indicated . . . . The unbundling obligation associated with DS1 loops is in no way limited by the rules we adopt today with respect to hybrid loops typically used to serve mass market customers. . . .

According to the Public Staff, this passage makes it clear that an ILEC may not refuse to make DS1 loops available to a requesting CLEC, based on fiber loop access "exemptions" that would otherwise apply, simply because the DS1 loops must be provisioned on a fiber optic facility. This assures that customers who require one or more DS1 loops to meet their service needs will be able to obtain them from competitive providers, as well as BellSouth. The Public Staff maintained that the Commission's language for Section 2.1.2.3 preserves this vital competitive access for all customers.

The Public Staff recommended that the Commission decline to modify the language it previously adopted for Sections 2.1.2, 2.1.2.1, and 2.1.2.3 of the *TRRO* amendments.

REPLY COMMENTS

BELLSOUTH: BellSouth stated in its reply comments that, since neither CompSouth nor the Public Staff had raised any new issues in their latest filings, it was not necessary for BellSouth to reply. BellSouth requested the Commission grant its Motion for Reconsideration and Clarification.

DISCUSSION

The Commission concludes that the Public Staff and CompSouth have put forward compelling justification in support of their position on this issue. The Commission agrees with the Public Staff that the language adopted in the *Change of Law Order* for Sections 2.1.2, 2.1.2.1, and 2.1.2.3 faithfully implements the FCC's current policy defining an ILEC's obligation to provide CLPs with unbundled access to FTTH, FTTC, and DS1 loops; that in Paragraph 325 of the *TRO*, the FCC found that "requesting carriers generally are impaired without access to unbundled DS1 loops;" and that Footnote 956 to that finding emphasized that this access was in no way limited by the technology employed to provide it, or by the nature of the customers to be served. Footnote 956 makes it clear that an ILEC may not refuse to make DS1 loops available to a requesting CLP, based on fiber loop access "exemptions" that would otherwise apply, simply because the DS1 loops must be provisioned on a fiber optic facility. The Commission believes that, logically, if the FCC had intended to limit the availability of DS1 loops in the MDU environment, it would have issued a specific conclusion to that effect, since the *MDU Order* (issued August 9, 2004) preceded the *TRRO*. This assures that customers who require one or more DS1 loops to meet their service needs will be able to obtain them from competitive providers, as well as BellSouth. Section 2.1.2.3, as set forth in the *Change of Law Order*, preserves this vital competitive access for all customers. Therefore, the Commission finds good cause to deny BellSouth's Motion for Reconsideration and Clarification.

CONCLUSIONS

The Commission finds it appropriate to deny BellSouth's Motion for Reconsideration and Clarification of Finding of Fact No. 20, thereby upholding and affirming its original decision in this regard.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission denies all objections to Findings of Fact Nos. 5, 13, 15, 18, and 20, thereby upholding and affirming its original decisions regarding these issues.

2. That the Commission will entertain no further comments, objections, or unresolved issues with respect to issues previously addressed in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of July, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

bp071006.01

Appendix A
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Glossary of Acronyms
Docket No. P-55, Sub 1549

Act	Telecommunications Act of 1996
ADSL	Asymmetrical Digital Subscriber Line
Agreement	Interconnection Agreement
ARMIS	Automated Reporting Measurement Information System
BellSouth	BellSouth Telecommunications, Inc.
CLEC	Competitive Local Exchange Company
CLP	Competing Local Provider
Commission	North Carolina Utilities Commission
CompSouth	The Competitive Carriers of the South
Covad	DIECA Communications, Inc., d/b/a Covad Communications Company
DS1	Digital Signal 1
DS3	Digital Signal 3
DSL	Digital Subscriber Line
EEL	Enhanced Extended Link (Loop)
FCC	Federal Communications Commission
FTTC	Fiber-to-the-curb
FTTH	Fiber-to-the-home
HDSL	High-bit-rate Digital Subscriber Line
ICA	Interconnection Agreement

IDSL	ISDN Digital Subscriber Line
ILEC	Incumbent Local Exchange Company (Carrier)
ISDN	Integrated Services Digital Network
Kbps	Kilobits Per Second

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LEC	Local Exchange Company
MDU	Multiple Dwelling Unit
MPOE	Minimum Point of Entry
OSS	Operations Support Systems
PMAP	Performance Measurements and Analysis Platform
Public Staff	Public Staff – North Carolina Utilities Commission
RNMs	Routine Network Modifications
SEEM	Self-Effectuating Enforcement Mechanism
Sprint	Sprint Communications Company, L.P.
SQM	Service Quality Measurement
TA96	Telecommunications Act of 1996
TELRIC	Total Element Long-Run Incremental Cost
TRO	Triennial Review Order
TRRO	Triennial Review Remand Order
UCL-S	Unbundled Copper Loop – Short
UNE	Unbundled Network Element
UNE-L	Unbundled Network Element – Loop
UNE-P	Unbundled Network Element – Platform

DOCKET NO. P-118, SUB 86

In the Matter of:

Application of ALLTEL Carolina, Inc.,	)	RECOMMENDED ORDER
for Approval of a Price Regulation Plan	)	APPROVING MODIFIED PRICE
Pursuant to G.S. 62-133.5(a)	)	REGULATION PLAN

HEARD: Thursday, December 15, 2005, in the Matthews Town Hall, 232 Matthews Station Street, Matthews, North Carolina

BEFORE: Hearing Examiner Dan Long, Presiding

APPEARANCES:

FOR ALLTEL CAROLINA, INC.:

Daniel C. Higgins
Burns, Day & Presnell, P.A.
2626 Glenwood Ave., Ste. 560
Raleigh, North Carolina 27608

FOR THE USING AND CONSUMING PUBLIC:

Elizabeth D. Szafran
Ralph J. Daigneault
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4326

Kevin L. Anderson
North Carolina Department of Justice
P.O. Box 629
Raleigh, North Carolina 27602-0629

BY THE HEARING EXAMINER: 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 the 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."

G.S. 62-133.5(a) requires notice and a hearing, allows different forms of price regulation as between different LECs, and requires the Commission to decide price regulation cases within 90 days subject to an extension by the Commission for an additional 90 days, or a total of 180 days from the filing of the Application. The statute requires the Commission to approve price regulation 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 that the Commission may adopt;

(iii) will not unreasonably prejudice any class of telephone customers, including telecommunications companies; and

(iv) is otherwise consistent with the public interest.

ALLTEL Carolina, Inc. ("ALLTEL") is currently operating pursuant to the price regulation plan that was the subject of the Commission's Order Approving ALLTEL's Revised Price Regulation issued in this docket on September 15, 1998 (the "Original Plan") as subsequently amended. G.S. 62-133.5(c) provides that "[a]ny 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." The Commission must approve the amended plan if it satisfies the four criteria quoted above. G.S. 62-133.5(c) further provides: "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."

On October 18, 2005, ALLTEL and the Public Staff – North Carolina Utilities Commission ("Public Staff"), collectively referred to as the "Parties," filed a Stipulation and Agreement with the Commission. In the Stipulation and Agreement, the Parties mutually agreed that the Small Local Exchange Carrier Price Regulation Plan for ALLTEL (the "Stipulated Plan" or "Plan") met and satisfied the four statutory criteria for Commission approval of a price regulation plan under G.S. 62-133.5(c) and requested Commission approval. ALLTEL advised the Commission that its Stipulated Plan was substantially identical to the revised price regulation plans recently approved by the Commission for other local exchange companies.

The Stipulated Plan modified the Original Plan with the following provisions:

- Reclassification of existing services into four new categories of service designated as Moderate Pricing Flexibility, Discretionary Pricing Flexibility, High Pricing Flexibility, and Total Pricing Flexibility.
- Services that would be classified in the Moderate Pricing Flexibility category include business and residential basic local exchange services and switched access charges applicable to interexchange carriers. Prices for 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.
- Initially, there would be no services that would be classified to the Discretionary Pricing Flexibility category. Prices for services placed into the Discretionary Pricing Flexibility category will be no higher than tariff rates but may be reduced to individual customers, for competitive reasons, below tariff rates at ALLTEL's discretion.
- Services that would be classified to the High Pricing Flexibility category include operator assisted local calls and optional business and residential calling features. Prices for these services could be increased by a maximum of 20% in each Plan year, provided that revenues for the category do not increase by more than two and one-half times the rate of inflation.
- Services in the Total Pricing Flexibility category include Centrex service. Prices for these services would not be regulated by the Plan.
- Financial penalties to be paid to customers if ALLTEL fails to meet service objectives established by the Commission.

On October 24, 2005, the Commission issued its Order Setting Hearings and Requiring Public Notice. This Order consolidated the public hearing and the evidentiary hearing for December 15, 2005, with respect to ALLTEL's request for approval of the Stipulated Plan. The

Order required that ALLTEL publish notice of the hearing in newspapers having general circulation in its service areas near Charlotte, Winston-Salem, Tryon, Sanford and Aberdeen once a week for two weeks beginning the week of October 31, 2005; that ALLTEL send the Notice to its customers by means of bill inserts or special direct mailing between November 1 and November 15, 2005; that ALLTEL prefile direct testimony no later than November 23, 2005; that the Public Staff and any other intervenor prefile direct testimony no later than December 5, 2005; that rebuttal testimony be filed no later than December 9, 2005; that petitions to intervene be filed no later than November 18, 2005; and that all the parties in this docket file witness lists, proposed order of witnesses and estimated cross-examination times no later than December 12, 2005.

On November 23, 2005, ALLTEL filed the direct testimony of Jayne Eve, Director of External Affairs for ALLTEL. On December 5, 2005, the Public Staff filed the direct testimony of Charles B. Moye, an Engineer with the Communications Division. Both witnesses supported the Stipulated Plan. On January 4, 2006, ALLTEL filed affidavits of publication establishing that public notice had been provided in accordance with the Commission's procedural order.

At the December 15, 2005 evidentiary hearing in Matthews, the Parties were present, as well as members of the public. The public witnesses consisted of Lee Myers, Steve Huff, and Robert Thore, who testified without objection. Public witnesses Myers and Huff generally testified in support of ALLTEL. Public witness Thore testified as to his belief that he was in a monopoly situation with no other local phone service provider available to him and expressed his concern as to the rate adjustment flexibility described in the public notice he had received from ALLTEL regarding the hearing. In addition, ALLTEL witness Eve and Public Staff witness Moye testified without objection. Although Alltel Corporation's proposed spin off of its wireline business, which includes ALLTEL, and merger of that business with VALOR Communications Group Inc. is not before the Commission, nor directly relevant to this proceeding, ALLTEL witness Eve testified at the hearing that ALLTEL will be affected by the spin-off in name only. She also testified that the new wireline company will continue to provide the same services on the same terms and conditions using the same network, and the spin-off is in the public interest as it is expected to better position the new wireline company to compete in the marketplace and provide telecommunications services to consumers in North Carolina at competitive rates. At the hearing, the Stipulation was entered into evidence without objection. ALLTEL and the Public Staff filed a Joint Proposed Order on January 17, 2006.

WHEREFORE, the Hearing Examiner makes the following

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. ALLTEL is a "local exchange company" as the term is defined in G.S. 62-3(16a). ALLTEL is currently subject to a price regulation plan pursuant to the provisions of G.S. 62-133.5(a) 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 ALLTEL 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.

EVIDENCE FOR 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.

EVIDENCE FOR 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 testimony and exhibits of ALLTEL witness Eve and Public Staff witness Moye. The Hearing Examiner has also taken into account the testimony of public witnesses Myer, Huff and Thore.

ALLTEL witness Eve testified as to the economic rationale for revising ALLTEL's Original Plan; the economic context in which the stipulated revisions to the Original Plan should be evaluated; the changes in competitive landscape for telecommunications services in the United States and North Carolina; and the effects of new technology and increased competitive options and the entry of larger companies such as Time Warner. In addition, witness Eve explained why ALLTEL sought to make the modification to the Original Plan. Specifically, witness Eve testified that the Stipulated Plan would enable ALLTEL to quickly react to competitive pressures and changing customer expectations and demand. The flexibility provided for in the Stipulated Plan would provide immediate as well as long-term benefits to many of ALLTEL's customers and would allow ALLTEL to better meet competitive challenges within its territory.

In her direct testimony, witness Eve discussed the detailed provisions of the Stipulated Plan, explained why it is consistent with the requirements of G.S. 62-133.5(a), and stated that it represents a compromise supported by representatives of the using and consuming public and ALLTEL. Witness Eve's testimony provided clear evidence that ALLTEL has experienced a net loss of access lines to competition, that such losses continue to date, and that the prospect for future losses through competition is high. Witness Eve testified to significant risk for traditional wireline local telephone companies from competition from wireless and Voice over Internet Protocol ("VoIP") providers.

Public Staff witness Moye also testified that developments have changed the landscape of the telecommunications industry in North Carolina since local competition was authorized by state and federal law. Specifically, witness Moye described these changes as the growth in access line competition from competing local providers (CLPs); the growth in wireless service; the halt and possible permanent reversal of access line growth for incumbent LECs; and the potential for further competition from new technologies. In addition, witness Moye testified that the Stipulated Plan satisfies the criteria of G.S. 62-133.5(a). Like witness Eve, he indicated that the Stipulated Plan is a reasonable compromise between ALLTEL and the Public Staff. The testimony of witnesses Eve and Moye establishes that, for many services in ALLTEL's service areas, price constraints imposed by the existence of competitors are current, real and generally effective, aiding the Commission's determination that the Stipulated Plan will result in affordable rates.

In Commission Rule R17-1(a) the Commission has defined basic local exchange service 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." In the Stipulated Plan basic local exchange service is included in the Moderate Pricing Flexibility Services category. However, the Stipulated Plan allows ALLTEL 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 a productivity offset of zero. The constraint for the High Pricing Flexibility Services category is set at two and one-half times the GDPPI minus the offset.

As witness Moye noted, the rate element constraints are based on a set percentage. Under the Stipulated Plan, the rate element constraint is 10% in the Moderate Pricing Flexibility Service category. In the High Pricing Flexibility Services category the rate element constraint is 20%. The Stipulated Plan also includes a minimum increase provision, under which any rate element in the Moderate Pricing Flexibility Services category may be increased on an annual basis by a minimum of ten percent (10%) or thirty-five cents ($0.35), whichever is greater, if it is priced on a flat-rated monthly basis, and 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 High Pricing Flexibility Services category with the following allowed minimum rate increases: twenty percent (20%) or fifty cents ($0.50), whichever is greater, for rate elements priced on a flat-rated monthly basis, and twenty percent (20%) or thirty cents ($.30), whichever is greater, for rate elements priced on a per-use basis.

The Attorney General opposed the increased pricing flexibility on the basis that it would permit ALLTEL to use its price for an indefinite period of time.

Notwithstanding, the position taken by the Attorney General, the Hearing Examiner concludes that the incremental increase in pricing flexibility is appropriate while still protecting the affordability of basic local exchange service. Prices for Moderate Pricing Flexibility Services in the aggregate can increase no more than the one and one half times the change in GDPPI. Aggregate price increases for rate elements in this category above this rate 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 ten percent (10%) for basic and twenty percent (20%) for non-basic service.

In reaching this conclusion, the Hearing Examiner notes that ALLTEL's Original Plan was approved almost eight years ago under competitive circumstances very different from those in existence today. The record shows that in the past five years, ALLTEL has lost more than 5% of its customer base, as a result of changes in technology and competition. In contrast, when ALLTEL's current rates were adopted there was no competition for basic service. The limited increase in pricing flexibility allowed under the Stipulated Plan for basic local exchange services and discretionary services is fully justified by the increased competition that exists in ALLTEL's North Carolina telecommunications market. It is also consistent with increased pricing flexibility approved for other North Carolina incumbent LECs.

EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO. 3 - SERVICE QUALITY

Finding of Fact and Conclusion of Law No. 3 was not disputed by any party. The Original Plan did not contain specific service quality measurements and self-enforcing service penalties. In contrast, in the Stipulated Plan there are provisions expressly relating to service quality measurements and provision for appropriate service quality penalties. The Commission retains powers and authority with regard to the provision of quality service. ALLTEL 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 Hearing Examiner concludes that the Stipulated Plan reasonably assures the continuation of basic local exchange service that meets the reasonable service standards established in Commission Rule R9-8.

EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO. 4 - NO PREJUDICE AMONG CUSTOMER CLASSES

ALLTEL witness Eve's testimony addressed the issue of whether the Stipulated Plan will unreasonably prejudice any class of telephone customers. She stated that, for several reasons, the Stipulated Plan will not result in such prejudice. First, she asserted that ALLTEL will continue to charge tariffed rates for services on non-discriminatory terms and conditions and that those prices will be restrained by the Stipulated Plan's pricing limits and by competition.

Second, customers in a position to negotiate customer-specific agreements will obtain prices that are constrained by the existence of competitive alternatives.

Third, the Stipulated Plan does not change any terms and conditions applicable to ALLTEL's relationships with other carriers, such as the terms of access tariffs, interconnection agreements, or wholesale service arrangements and numbering, and applicable nondiscrimination requirements remain in effect.

Finally, the Stipulated Plan uses existing rates as a starting point and therefore preserves the pricing for basic residential services. At the same time, the Stipulated Plan permits ALLTEL to modify its basic residential prices, over time, without necessarily making corresponding changes in basic business prices that begin at higher levels. In this way, the Stipulated Plan preserves a balance between the treatment that residential customers have traditionally enjoyed and the possibility that basic business rates may require a somewhat different treatment in the future because they are more competitive.

Public Staff witness Moye did not take issue with witness Eve's analysis and agreed that the Stipulated Plan will not be unreasonably prejudicial to customers.

The Hearing Examiner finds the testimony of witnesses Eve and Moye to be persuasive and concludes that the Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

EVIDENCE FOR FINDING OF FACT AND CONCLUSION OF LAW NO. 5 - PUBLIC INTEREST STANDARD

The public interest standard is one the Commission has employed in its deliberations for many years. Notwithstanding the statement made by Public witness Thore setting forth certain arguments in opposition to approval of the Stipulated Plan and arguments put forth by the Attorney General in opposition to approval of the Stipulation Plan, the Hearing Examiner 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 ALLTEL will continue to provide adequate service to its customers. Third, the Stipulated Plan contains specific service performance measures and penalties. Fourth, the Hearing Examiner 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.

At the same time, the Hearing Examiner 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 had not yet progressed to the point where it could discipline prices effectively in ALLTEL's North Carolina service territories.

In addressing this concern, the Hearing Examiner 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 ALLTEL's service area. The assignment of services to categories in the Stipulated Plan was determined by negotiation between ALLTEL and the Public Staff and based on previously approved plans of other incumbent local exchange providers. 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 Hearing Examiner 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 public interests standards, 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 Hearing Examiner notes that two of the three public witnesses testified in favor of the Stipulated Plan. Public witness Meyer, while being Mayor of Matthews, is also a long time resident and businessman within the ALLTEL service area and he described ALLTEL's role in the community, acknowledging ALLTEL as one of Matthew's leading corporate citizens for what the company does and gives back to the community. Witness Huff supported ALLTEL's plan to obtain greater pricing flexibility through service bundling. Witness Huff explained that from a business perspective, the bundling of rates has been more cost-effective, rather than costing his company more.

The Hearing Examiner acknowledges that Public witness Thore expressed some concerns about the Stipulated Plan stating his belief that a monopoly for local service in Matthews still exists.

The Attorney General also expressed concerns in his brief, but the Hearing Examiner notes that the Attorney General submitted no evidence to support his concerns; and it is the Hearing Examiner's evaluation that the Attorney General has not recognized the dramatic change in competitive circumstances that have occurred since ALLTEL's first plan was adopted which have tended to diminish the need for direct regulatory supervision over prices. For example, as stated in witness Eve's testimony, 30 interconnection agreements between ALLTEL and CLPs are on file with the Commission. The Hearing Examiner takes note of the Commission's recent approval of an agreement between ALLTEL and Time Warner Cable Information Services in Docket P-118, Sub 145, which will bring further competitive options to Matthews and other areas where ALLTEL provides service. Accordingly, the Hearing Examiner believes the evidence shows that the current level of competition in ALLTEL's local exchange service area is sufficiently advanced, and the Hearing Examiner, therefore, concludes that the Stipulated Plan is consistent with the public interest given the current level of competition in ALLTEL's service territory. Furthermore, the Hearing Examiner recognizes that, under the Stipulated Plan, the Commission retains the regulatory oversight authority for any request by ALLTEL 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.

FINAL OBSERVATIONS AND CONCLUSIONS

Consistent with the law and policy of this State, ALLTEL 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 Hearing Examiner 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 1996. The Hearing Examiner believes that the flexibility afforded by the Stipulated Plan will enable ALLTEL to compete effectively and continue to provide reasonably affordable basic local exchange service. The Hearing Examiner's decision to approve the Stipulated Plan is based upon an analysis of competitive conditions in ALLTEL's service territory, and should not be understood as indicating that a different plan would not be appropriate given the existence of different competitive conditions. Although the Hearing Examiner is aware of Alltel Corporation's proposed spin off of its wireline business, that transaction is not before the Commission, is not directly relevant hereto, and it does not affect the decision reached in this docket.

IT IS, THEREFORE, ORDERED that the Stipulated Plan be, and the same is hereby, approved for implementation by ALLTEL effective no later than March 15, 2006, provided that ALLTEL shall, not later than February 15, 2006, refile the Stipulated Plan bearing an effective date not later than March 15, 2006.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of January, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb011906.01

DOCKET NO. P-772, SUB 8
DOCKET NO. P-913, SUB 5
DOCKET NO. P-1202, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Petition of NewSouth Communications) Corp. et al. for Arbitration with BellSouth) Telecommunications, Inc.)	ORDER APPROVING COMPOSITE AGREEMENTS AND CLOSING DOCKETS

BY THE PRESIDING COMMISSIONER: On July 14, 2006, BellSouth Telecommunications, Inc. (BellSouth) and Xspedius Communications, LLC (Xspedius) filed a copy of their interconnection agreement. The parties stated that the agreement was negotiated pursuant to Section 251 and Section 252 of the Telecommunications Act of 1996 (the Act) and also may contain terms and conditions for products and services voluntarily agreed to by the parties outside of the scope of Section 251 and Section 252 of the Act.

Also on July 14, 2006, BellSouth and NuVox Communications, Inc. (NuVox) filed a copy of their interconnection agreement. The parties stated that the agreement was negotiated pursuant to Section 251 and Section 252 of the Act and also may contain terms and conditions for products and services voluntarily agreed to by the parties outside of the scope of Section 251 and Section 252 of the Act.

The Commission has reviewed the composite agreements noted above and concludes that good cause exists to approve the agreements. Further, the Presiding Commissioner finds it appropriate to close these dockets.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp081506.01

DOCKET NO. P-55, SUB 1630
DOCKET NO. P-140, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of AT&T, Inc. and BellSouth	)	ORDER APPROVING TRANSFER
Corporation for Indirect Change of Control	)	OF CONTROL

BY THE COMMISSION: On March 31, 2006, AT&T, Inc. (AT&T) and BellSouth Corporation (BellSouth Corp.; collectively, Petitioners) jointly filed an Application requesting Commission approval pursuant to G.S. 62-111(a)[1] to transfer control of certain competing local providers (CLPs)—namely, BellSouth Long Distance, Inc. (BSLD) and BellSouth Telecommunications, Inc. (BellSouth)—in connection with a planned merger between AT&T, Inc. and BellSouth Corporation. On April 12, 2006, the Commission granted Petitions to Intervene filed by Time Warner Telecom of North Carolina LP and US LEC of North Carolina, Inc. (collectively, Time Warner). On April 21, 2006, the Commission granted intervention to NuVox Communications, Inc.

Time Warner Motion

On May 12, 2006, Time Warner filed a Motion for Procedural Schedule and Hearing. In this consolidated proceeding, Time Warner noted that the Petitioners are requesting approval of the indirect control of CLP certificates held by BellSouth and BSLD in connection with the transfer of control of BellSouth Corp. and its subsidiaries to AT&T, Inc. Time Warner identified several aspects of the proposed combination which it believes deserve regulatory scrutiny through a deliberative process in which the parties can file testimony and cross-examine witnesses.

The first concern had to do with the extent of horizontal concentration. Time Warner stated that the application discloses that six separate entities holding certificates in North Carolina would be combined under common ownership as a result of the merging. They are: (1) SBC Long Distance, LLC, (2) AT&T Communications of the Southern States, LLC, (3) TCG of the Carolinas, Inc., (4) SNET America, Inc., (5) BellSouth and (6) BSLD. Time Warner argued that the application does not disclose the extent of competition among these entities in various markets in North Carolina in any but the most generalized fashion and that allowing such consolidation might lessen competition and create confusion among consumers.

The second concern was the extent to which the merger may impact fair competition, especially as the interconnection arrangements and the procurement of interconnection services and related facilities by Time Warner from the Petitioners. Time Warner noted that in its January 2006 presentation titled "North Carolina Public Utility Infrastructure and Regulatory Climate," the

[1] G.S. 62-111(a) reads in relevant part as follows: "No franchise now existing or hereafter issued under the provisions of this Chapter...shall be sold, assigned, pledged, or transferred, nor shall any control thereof be changed through stock transfer or otherwise, or any rights thereunder leased, nor shall any merger or combination affecting any public utility be made through acquisition or control by stock purchase or otherwise, except after application to and written approval by the Commission, which approval shall be given if justified by the public convenience and necessity...."

Commission noted certain market failures and instability in the competitive marketplace. Nothing has changed to lessen these concerns.

Lastly, Time Warner argued that the Petitioners would not be prejudiced by a more deliberate approach to review and that the Federal Communications Commission is early in its 180-day merger review.

AT&T and BellSouth Response

On May 15, 2006, the Petitioners filed a Response in Opposition to Time Warner's Motion. The Petitioners noted the comparative lateness of Time Warner's Motion, and argued that Time Warner misunderstood not only the scope of this proceeding but the effects that the proposed merger will have on the relevant CLP subsidiaries. As the Petitioners explained in their Joint Application, this proceeding is concerned only with the transfer of indirect control of BSLD and of BellSouth *in its capacity as a CLP operating outside of its incumbent local service area in North Carolina.* Because BellSouth is subject to price regulation under G.S. 62-133.5 within its incumbent service territory, the merger approval provision of G.S. 62-111(a) does not apply to BellSouth in its capacity as an ILEC.[1] Thus, Time Warner's purported concerns about fair competition are misdirected because there is no nexus between Time Warner and US LEC on the one hand and the BellSouth CLP subsidiaries on the other. To the extent that Time Warner has concerns about business relationships with BellSouth in its capacity as an ILEC, this is not the proceeding to consider those issues. In addition, Time Warner is wrong to suggest that this merger will have any adverse effect on horizontal concentration. Competition in this state is well-established and will not be affected by this merger. The holding-company merger will not change the direct ownership of the CLP subsidiaries or this Commission's regulatory jurisdiction over them. There is thus no justification to grant Time Warner's request to delay this proceeding by conducting a full evidentiary hearing.

May 15, 2006, Regular Commission Conference

This matter came before Regular Commission Conference on May 15, 2006. Four persons addressed the Commission: Mr. George Sessoms, presenting the item to approve the transfer of control as requested and described in the Application on behalf of the Commission Staff; Mr. Marcus Trathen, representing Time Warner; and Mr. Dwight Allen and Ms. Susan Ockleberry, representing Petitioners.

Commission Staff. Mr. Sessoms explained that AT&T is a Delaware corporation with its principal place of business in San Antonio, Texas. AT&T is a holding company and its subsidiaries provide domestic and international voice and data communications services to residential, business and government customers around the world. AT&T wholly owns four subsidiaries which are authorized to provide local exchange and exchange services as CLPs and/or intrastate interexchange services in North Carolina pursuant to Certificates of Public Convenience and Necessity (Certificates) granted by the Commission. These subsidiaries are AT&T Communications of the Southern States, LLC; TCG of the Carolinas, Inc.; SBC Long Distance, LLC d/b/a AT&T Long Distance; and SNET America d/b/a AT&T Long Distance East. However, according to the

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

Application, these AT&T subsidiaries are not affected by the planned merger and their ownership structure will remain entirely unchanged.

BellSouth Corp. is a Georgia corporation with its headquarters in Atlanta, Georgia. BellSouth Corp. is also a holding company and its subsidiaries provide voice and data communications services to substantial portions of customers in the southeastern United States. Two of BellSouth Corp.'s wholly owned subsidiaries, BSLD and BellSouth, are authorized to provide local exchange and exchange access services as CLPs in North Carolina. BSLD was granted a CLP Certificate by the Commission in Docket No. P-654, Sub 5 on September 24, 2004. (BSLD is also authorized to provide intrastate interexchange services pursuant to a Certificate granted by the Commission in Docket No. P-654, Sub 0 on November 26, 1997, but providers of only interexchange services are exempt from the provisions of G.S. 62-111(a) pursuant to the Commission Order dated January 2, 2004 in Docket No. P-100, Sub 72b.) BellSouth was granted a CLP Certificate by the Commission, to provide such services in all geographic areas outside its incumbent service territory, in Docket No. P-55, Sub 1117 on June 15, 1999. (BellSouth is also an incumbent local exchange carrier which operates under a Commission approved price plan. However, G.S. 62-133.5(g) exempts local exchange companies subject to price regulation from the provisions of G.S. 62-111(a)).

Mr. Sessoms stated that AT&T and BellSouth Corp. entered into an Agreement and Plan of Merger on March 4, 2006. To implement the planned merger, a temporary and special purpose subsidiary of AT&T will merge with and into BellSouth Corp., with BellSouth Corp. being the surviving corporation. At the time of the merger, shareholders of BellSouth Corp. will exchange their shares of stock for shares of AT&T stock.

Following the merger, BellSouth Corp. will become a wholly-owned and direct subsidiary of AT&T. BSLD and BellSouth will continue to be directly owned by BellSouth Corp. However, BSLD and BellSouth will be ultimately owned and indirectly controlled by AT&T because AT&T will own the shares of their corporate parent, BellSouth Corp. Therefore, the Application requests Commission approval pursuant to G.S. 62-111(a) to transfer control of BSLD and BellSouth, in their capacity as CLPs, in connection with the planned merger of AT&T and BellSouth Corp.

According to the Petitioners, the proposed transaction will be transparent to customers in North Carolina. BSLD and BellSouth will continue to exist in their current form after the merger is completed. There will be no transfer of assets or Certificates and the merger will have no effect on the rates, terms, and conditions of service that these entities currently provide.

Mr. Sessoms noted that the Applicants submitted that Commission approval of the proposed transaction is in the public interest for several reasons as set forth in the Application. In the short-run, the merger and transfer of control will be transparent to North Carolina customers since it will have no effect on the rates, terms, and conditions of services currently provided by AT&T and BellSouth Corp. subsidiaries. Ultimately, the proposed transaction should allow the companies to integrate their networks, improving performance and service reliability, and to combine their research and development capabilities, leading to increased innovation and accelerated development of new products and services.

Accordingly, Mr. Sessoms recommended that the Commission issue an order approving the transfer of control as requested and described in the Application.

Time Warner. While alluding to the arguments made in Time Warner's May 12, 2006, Motion concerning horizontal concentration and fair competition, Mr. Trathen instead concentrated on the proposition that the Commission has jurisdiction to significantly broaden the scope of its investigation from the BellSouth CLPs to BellSouth the ILEC. He laid out two main arguments. The first argument sought to bring BellSouth Corp., the holding company, under the Commission's merger jurisdiction and, presumably by that device, to bring in BellSouth the ILEC. This argument hinged upon the phrase in G.S. 62-111(a) to the effect that the Commission has jurisdiction over "any merger or combination affecting any public utility." Mr. Trathen contended that BellSouth Corp. was a "public utility" within the meaning of G.S. 62-3(23)(c).[1] The second argument was that BellSouth the ILEC was a fit subject for merger investigation because BellSouth the ILEC was also a CLP. The inference was that this CLP ownership furnished sufficient basis for investigating the ILEC merger, notwithstanding the ILEC exemption under G.S. 62-133.5(g).

Petitioners. Mr. Allen rejected Time Warner's arguments both in the May 12, 2005, filing and at Regular Commission Conference. He emphasized the existence of the G.S. 62-133.5(g) exemption for BellSouth the ILEC as being dispositive of the Commission's limited jurisdiction in this matter. He noted that the Commission had noted this limited jurisdiction in other mergers, most explicitly in the Verizon/MCI merger. He also mentioned the extreme smallness of the BellSouth CLPs in terms of customer base and that only two of the CLPs mentioned in the Application were BellSouth CLPs, the others being associated with AT&T and whose status would not change as a result of the merger. He expatiated on the benefits of the merger for the end-user customers of the Petitioners and doubted the sincerity of the concerns expressed by Time Warner for competition, as it belongs to a multi-billion dollar conglomerate.

Others. No other persons spoke at Conference. However, Petitioners stated without demur from the Public Staff, who were present, that the Public Staff supported the recommendation for approval. The Attorney General did not speak on the item after having been given an opportunity to do so.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that good cause exists to deny Time Warner's Motion for Procedural Schedule and Hearing and issue an Order approving the transfer of control as requested by Petitioners for the reasons described in the Commission Staff's recommendation. The Commission does not believe that Time Warner has made convincing arguments that the Commission should expand the scope of an investigation into this merger, especially in light of the exemption for BellSouth the ILEC in G.S. 62-133.5(g).

The first argument of Time Warner, as noted above, relied on the provision in G.S. 62-111(a) that provided that mergers "affecting any public utility" are not to be allowed unless there has been application to, and written approval from, the Commission if such approval is justified by the public convenience and necessity. Clearly, this provision does not affect BellSouth the ILEC as such, because G.S. 62-133.5(g) specifically exempts ILECs subject to price regulation from

[1] G.S. 62-3(23)(c) reads in pertinent part as follows: "The term 'public utility' shall include all persons affiliated through stock ownership with a public utility doing business in this State as a parent corporation...to such extent that the Commission shall find that such affiliation has an effect on the rates or service of such public utility."

G.S. 62-111(a). Rather, Time Warner argues that it refers to the holding company, BellSouth Corp., on the basis that BellSouth Corp. is a "public utility" under G.S. 62-3(23)(c). This provision provides that "public utility" includes "all persons affiliated through stock ownership with a public utility doing business in this State as a parent corporation or a subsidiary corporation...*to such extent that the Commission shall find such affiliation has an effect on the rates and service of such utility.*" (emphasis added). Time Warner suggests that BellSouth Corp. is such a parent, and it is not an ILEC subject to price regulation and thus exempt from G.S. 62-111(a).

However, even assuming arguendo that there is an effect on rates and service such as to render BellSouth Corp. a public utility, Time Warner's argument does not lead where it evidently wants to go—that is, to an examination of, and presumably conditions upon, the activities of BellSouth the ILEC. Inconveniently for Time Warner's argument, BellSouth the ILEC falls squarely within the G.S. 62-133.5(g) exemption, so no inquiry on this basis is possible. At most, the argument, if accepted, could lead to the CLPs; but the CLP transfer is already being examined under G.S. 62-111(a).

Time Warner's second argument was related to the fact that BellSouth the ILEC had obtained CLP certification. Time Warner argued that this in effect negated BellSouth the ILEC's exemption under G.S. 62-133.5(g) and rendered BellSouth the ILEC as a whole "fair game" for comprehensive merger inquiry. This is not a convincing argument. BellSouth actually holds two franchises, one as an ILEC and one as a CLP. It is a simple matter analytically and practically to separate consideration of BellSouth the ILEC and BellSouth the CLP. Besides, the logic of Time Warner's argument works both ways. If it can be argued that the existence of BellSouth the CLP makes BellSouth the ILEC fair game, the reverse can be argued as well with perhaps even greater force. Indeed, given their relative sizes and importance, the BellSouth ILEC exemption under G.S. 62-133.5(g) could be argued to apply pari passu to BellSouth the CLP, and thus neither should be subject to G.S. 62-111(a).

Lastly, the Commission notes that the holding of evidentiary hearings regarding mergers and acquisitions under G.S. 62-111(a) is discretionary. The statute simply says that application must be made and written approval be given if justified by the public convenience and necessity. Thus, even were the Commission to accept Time Warner's jurisdictional arguments to widen the scope of this proceeding, this would not necessarily equate to the type of proceeding that Time Warner seeks. Time Warner has raised concerns about horizontal concentration and fair competition, but Time Warner does not lack for options should it believe itself to be harmed and should it wish to pursue them, most notably in complaint actions or arbitrations.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of May, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

dl051806.01
Commissioners James Y. Kerr, II and William T. Culpepper, III did not participate.

DOCKET NO. W-1075, SUB 5

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by KRJ Utilities Company for a Certificate of Public Convenience and Necessity to Provide Water and Sewer Utility Service in Rockbridge Subdivision in Wake County, North Carolina, and for Approval of Rates	)))))	ORDER GRANTING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVING RATES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Thursday, September 21, 2006

BEFORE: Commissioner William T. Culpepper, III, Presiding; and Commissioners Lorinzo L. Joyner and James Y. Kerr, II

APPEARANCES:

For Applicant KRJ, Inc.:

M. Gray Styers, Jr., and Stephon J. Bowens, Blanchard, Jenkins, Miller, Lewis & Styers, PA, 1117 Hillsborough Street, Raleigh, North Carolina 27603

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 September 8, 2004, KRJ Inc., d/b/a KRJ Utilities Company (KRJ or Applicant), filed an application with the Commission seeking a Certificate of Public Convenience and Necessity (CPCN) to provide water and sewer utility services in the Rockbridge Subdivision in eastern Wake County and for approval of rates. On September 13, 2004, the Commission issued an Order Declaring Utility Status. On January 14, 2005, at the request of KRJ, the Commission issued an Amended Order Declaring Utility Status to clarify that the Applicant was applying for a CPCN for both water and sewer utility services.

On September 6, 2005, KRJ filed an amended application to adjust the proposed rates, based in part upon the requirements of the DWQ permit.

On July 28, 2006, KRJ's Counsel made a filing with the Commission indicating that KRJ and the Public Staff had been unable to agree on a rate design for the wastewater utility component of the Application and requested to be heard on oral arguments at the August 14, 2006, Regular Staff Conference.

On August 11, 2006, KRJ filed confidentially, under seal, certain contracts pertaining to the chain of title and ownership of the Rockbridge Subdivision property and the purchase of 407 lots and amenity areas in Rockbridge. KRJ also filed a Response to Public Staff Report on August 11, 2006.

This matter initially came before the Commission for consideration at the regular staff conference on August 14, 2006. Counsel for the Public Staff and counsel for KRJ provided oral arguments regarding the rate design issue. Following those oral arguments, on August 18, 2006, the Commission issued an Order Scheduling Docket for Hearing.

Consistent with the scheduling deadlines set forth in the order, KRJ filed the Direct Testimony of Robert Stafford on September 1, 2006. The Public Staff filed the Joint Testimony of Katherine Fernald and Babette McKemie on September 11, 2006. KRJ next filed Rebuttal Testimony of Robert Stafford on September 19, 2006. No other party intervened or filed testimony.

On September 21, 2006, the Commission conducted an evidentiary hearing. At the hearing, the parties' witnesses testified and were cross examined. In response to the Presiding Commissioner's request, KRJ filed certain contracts confidentially on September 29, 2006.

On October 27, 2006, KRJ and the Public Staff filed with the Commission a Stipulation which settled the disputed issues and a Joint Proposed Order encompassing the Stipulation for the Commission to consider. On November 2, 2006, KRJ filed an amendment to the Stipulation addressed in the Proposed Order.

On November 7, 2006, as required by the Stipulation, KRJ filed an Availability Fees Agreement entered into with Stafford Land Company (Stafford Land), the developer of Rockbridge, and a Utility Rates Disclosure Agreement which it entered into with both Stafford Land and K. Hovnanian Homes of North Carolina, Inc., (K. Hovnanian Homes) the initial purchaser of all lots in Rockbridge.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. KRJ is properly before this Commission seeking approval of a Certificate of Public Convenience and Necessity pursuant to N.C.G.S. § 62-110 to provide water and sewer utility services in the Rockbridge Subdivision in Wake County and for approval of rates.

2. The service area that is the subject of this proceeding is shown on the plans attached as Exhibit 10 to the application form filed in this docket.

3. There are presently no customers being served in the Rockbridge Subdivision. KRJ expects eventually to serve 407 residential customers in this subdivision.

4. KRJ presently holds a water franchise for one system serving approximately 176 customers. KRJ's record of service for that system is satisfactory.

5. KRJ has the managerial, financial, and technical capacity to provide water and sewer service in this service area.

6. The currently approved water system for Rockbridge consists of two wells, a 185 gpm well with a 25 hp submersible well pump, and a 35 gpm well with a 7.5 hp submersible well pump. The system also includes a treatment building with chlorination system, caustic soda chemical feed, and a 150,000 gallon elevated storage tank. The plans are approved by the North Carolina Division

of Environmental Health (DEH) under serial number 05-01495, dated April 25, 2006. Also, on June 26, 2006, DEH approved the plans for the water distribution system serving Phases 1 & 2 of Rockbridge under serial number 06-00506. The planned water distribution system consists of 4-inch, 6-inch, 8-inch and 12-inch PVC and ductile iron water mains and appurtenances.

7. The planned sewer system in Rockbridge consists of an influent pump station, a 125,000 gallon per day (gpd) wastewater treatment plant (currently permitted for 116,000 gpd) and reclamation facility consisting of flow equalization, dual process trains consisting of anoxic process cells, aerobic process cells, gravity clarification, gravity filtration system, liquid chlorine storage, disinfection, UV disinfection, and dechlorination, a 5-day upset pond, a 12,750,000 gallon long term storage pond, and approximately 42 acres of spray irrigation fields. The plans for this installation are approved under Permit No. WQ0024320 dated May 20, 2005. Also, on December 19, 2005, DWQ approved the plans for the sewer collection system to serve Phases 1 & 2 of Rockbridge, consisting of 8-inch and 10-inch gravity sewer mains, under Permit No. WQ0029621.

8. Robert R. Stafford is the president of KRJ, and owns 50% of KRJ's stock, with his wife, Katherine A. Stafford, owning the remaining 50%.

9. Robert R. Stafford is also the president of Stafford Land Company (Stafford Land), a land development company, which is owned by members of his family, including his wife, Katherine A. Stafford.

10. Stafford Land and KRJ have common ownership, and therefore, are affiliated entities.

11. On April 15, 2003, Stafford Land entered into a contract with Eden Croft Development Company, Inc. and Gaddy Properties Limited Partnership (hereinafter collectively referred to as the Gaddys) to purchase the raw land currently being developed as the Rockbridge Subdivision.

12. On August 10, 2005, KRJ entered into a Utilities Agreement with the Gaddys, covering the provision of water and sewer service to the Rockbridge Subdivision.

13. On November 23, 2005, Stafford Land, an affiliated company, purchased the property on which the Rockbridge Subdivision is located and, thereby, became successor in interest to the terms of the KRJ/Gaddy Utilities Agreement.

14. Under the Utilities Agreement, the developer will install and contribute to KRJ the water distribution and sewer collection systems. The developer will also contribute to KRJ all necessary well lots, elevated tank lot, water reclamation facility sites, and reclaimed water reuse sites. KRJ will install the wells, water pumping and treatment facilities, water storage tanks, wastewater reclamation and treatment facilities, and reclaimed water storage, pumping, distribution, reuse, and irrigation facilities.

15. Based on the distribution of plant costs set forth in the Utilities Agreement, the developer will be paying approximately 20% of the total sewer system costs, such that the utility is paying approximately 80%, or $10,125 per lot. KRJ will recover $8,000 of the estimated $10,125 per lot cost for the sewer system through tap fees. This sewer tap fee of $8,000 per residential equivalent unit (REU) will be paid by the developer and/or builder for each connection.

16. In future rate proceedings, the sewer plant costs to be recovered from future customers through the collection of tap fees will be considered to be excess capacity, and will not be included in rate base.

17. All lots should be charged for availability rates, including those owned by the developer or builders. Pursuant to the Stipulation between the Public Staff and KRJ, Stafford Land shall pay the monthly availability rates on all lots not receiving service once, either (a) the plats creating them are recorded in the Wake County Register of Deeds office, or (b) the certification by the engineer of record of the completion of construction of the wastewater treatment and reclamation facility and its commencement of operations, whichever is later. These availability rates and conditions related thereto have been established by an Availability Fees Agreement that has been entered into between Stafford Land and KRJ and filed with the Commission pursuant to the Stipulation.

18. Pursuant to the Stipulation between the Public Staff and KRJ, agreement has been executed by the developer of the Rockbridge Subdivision, Stafford Land, and the homebuilder, K. Hovnanian Homes, and filed with the Commission, whereby the utility rates in Rockbridge Subdivision will be disclosed in the marketing materials, with lot purchase agreements, and in the restrictive covenants pertaining to all lots in the Rockbridge Subdivision, to notify future customers in Rockbridge of the utility rates prior to their purchasing lots or residences.

19. A bond in the amount of $70,000 for water and sewer utility service has been posted with the Commission.

20. KRJ shall file annual reports with the Commission in this docket on the progress of construction, compliance with the notice provisions of this Order, the financial status of the utility, and the number of customers connected to the system until 90% (367) homes in Rockbridge are receiving utility service.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-6

The evidence supporting these findings is contained in the official files and records of the Commission and the testimony of KRJ witness Stafford and Public Staff Witnesses Fernald and McKemie. These findings are essentially informational, procedural or jurisdictional in nature and are based on uncontested evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-15

The evidence supporting these findings is contained in the official files and records of the Commission, including the filed Utilities Agreement between KRJ and the Gaddys, the testimony of KRJ witness Stafford and Public Staff witnesses Fernald and McKemie, and the Stipulation.

Although the Public Staff and KRJ disagreed as to the sewer rate design and the allocation of sewer plant costs among the utility and affiliated developer, and the resulting level of tap fees and rates, that disagreement has been resolved with the Stipulation. In the Stipulation, the parties have agreed that KRJ will collect a sewer tap fee of $8,000 per REU from the developer and/or builder to offset the cost of the sewer system. In future rate proceedings, sewer plant costs to be recovered from future customers through the collection of tap fees will be considered to be excess capacity, and will not be included in rate base.

The Commission concludes that the builder and/or developer should pay a sewer tap fee of $8,000 per REU to offset the plant costs. Furthermore, in future rate proceedings, sewer plant costs to be recovered from future customers through the collection of tap fees will be considered to be excess capacity, and will not be included in rate base.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding is contained in the official files and records of the Commission, the testimony of KRJ witness Stafford and Public Staff witnesses, and the Stipulation.

KRJ is requesting, and the Public Staff has recommended, approval of availability rates, which will help provide cash flow to the utility until the lots are built upon and receiving service. Pursuant to the Stipulation, these availability rates, which are to be paid by the developer or builder, will be due and owing on lots beginning on the last day of the first full month after either (a) the plats creating them are recorded in the Wake County Register of Deeds office, or (b) the certification by the engineer of record of the completion of construction of the wastewater treatment and reclamation facility and its commencement of operations, whichever is later, regardless of whether or not a utility main is located within 75 feet of the boundary of the lot at that time. The obligation to pay an availability fee for each lot shall end on the last day of the month in which service is commenced to the ratepayer on that lot. Pursuant to the Stipulation, KRJ has filed with the Commission an agreement executed by Stafford Land that incorporates the foregoing terms. The Commission concludes in its discretion that charging these availability rates under these terms is appropriate and reasonable. The disclosure and assessment of availability rates shall comply with Commission Rules R7-36 and R10-23.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding is contained in the official files and records of the Commission, the testimony of KRJ witness Stafford, and the Stipulation.

KRJ has offered, and the Commission concludes that it is appropriate to require KRJ to take several steps to ensure that future ratepayers receive notice of these rates prior to their purchasing their lots and residences in Rockbridge. Pursuant to the Stipulation between KRJ and the Public Staff, KRJ has filed with the Commission an agreement whereby the developer, Stafford Land and/or the homebuilder, K. Hovnanian Homes, have committed themselves to the following after KRJ has provided written notification of the approved rates: (1) K. Hovnanian Homes shall notify each of its home purchasers of the utility rates by attaching the Schedule of Rates as an addendum to the purchase contract; (2) Stafford Land shall disclose the rates in the recorded restrictive covenants for the lots in Rockbridge Subdivision[1], using language substantially similar to that set forth in Mr. Stafford's testimony (Tr. p. 14); and (3) the marketing materials for the sale of lots and/or houses in Rockbridge, substantially similar to Exhibit F to witness Stafford's testimony, shall be made available to potential purchasers of lots and homes in Rockbridge and shall include a disclosure of the utility rates.

[1] Such a provision in the Restrictive Covenants shall note that the rates could be changed by the Utilities Commission in a general rate case, and the covenants shall be amended (by the attachment of an appendix or otherwise) at the time of any such change.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-20

The Public Staff has recommended, and KRJ has agreed, that KRJ shall post a bond, as required pursuant to N.C.G.S. § 62-110.3, in the amount of $70,000. On June 26, 2006, KRJ posted the recommended bond. On November 20, 2006, KRJ filed an amendment to its letter of credit with the Commission. The amendment satisfied the Commissions' surety requirements.

Based on the foregoing, the Commission concludes that (a) the Stipulation should be approved, (b) the water and sewer utility franchise requested by KRJ in Rockbridge Subdivision should be granted and the agreed upon rates approved, and (c) the Amended Irrevocable Letter of Credit filed in this proceeding, as surety for the bond in the amount of $70,000, should be accepted.

In addition, the Commission will require that KRJ file annual reports to include a narrative informing the Commission and Public Staff of the progress of construction, compliance with the notice provisions of this Order, KRJ's actual costs and financial status, and the number of customers connected to the system as hereafter ordered.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation entered into by the Public Staff and the Applicant is hereby approved.

2. That Appendix A shall constitute Applicant's Certificate of Public Convenience and Necessity to provide water and sewer utility services in the Rockbridge Subdivision in Wake County, North Carolina.

3. That the Schedule of Rates, attached hereto as Appendix B, shall be approved upon the issuance of this Order. These Rates are deemed to be filed with the Commission pursuant to G.S. Section 62-138.

4. That all platted lots not receiving service shall be charged availability rates, including those owned by the developer or builders, consistent with the terms of the Stipulation, this Order, and Appendix B. KRJ shall comply with the disclosure requirements for availability rates set forth in Rules R7-36 and R10-23.

5. That KRJ shall file annual reports beginning on October 31, 2007, on the status of this subdivision as of September 30th of each year. These annual reports shall include a narrative on the progress of construction, compliance with the notice provisions of this Order, KRJ's actual costs and the financial status of the utility, and the number of customers connected to the system. KRJ will continue to file these annual reports until 90% (367) of the homes in Rockbridge are receiving utility service.

6. That in all future proceedings, the sewer plant costs to be recovered from future customers through the collection of tap fees shall be considered to be excess capacity, and shall not be included in rate base.

7. That the Irrevocable Letter of Credit filed in this proceeding, as surety for the bond in the amount of $70,000 required by the Commission, is hereby accepted and approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah112906.05

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1075, SUB 5

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

KRJ Utilities Company
is granted

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
for water and sewer utility service

in
ROCKBRIDGE SUBDIVISION

Wake County, North Carolina

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF RATES

for
KRJ UTILITIES COMPANY

for water and sewer utility service in

Rockbridge Subdivision

Wake County, North Carolina

Metered Water Rates:

Base charge, zero usage, per REU	$ 15.00
Usage charge, per 1,000 gallons	$ 1.55

Sewer Service Rates:

Flat monthly residential rate, per REU	$ 72.69

Availability Rates: 1/

Water monthly availability rate, per REU	$ 15.00
Sewer monthly availability rate, per REU	$ 70.00

Tap Fees:

Water, per REU	$ 1,000
Sewer, per REU	$ 8,000

Reconnection Charge:

If water service cut off by utility for good cause:	$ 15.00
If water service discontinued at customer's request:	$ 15.00

1/ Developer shall pay monthly availability fees on all lots not receiving service once plat creating lots is recorded.

APPENDIX B
PAGE 2 OF 2

Returned Check Charge:	$25.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

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Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1075, Sub 5, on this the 30th day of November, 2006.

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 AUTHORIZING SURCHARGE IN LIEU OF ABANDONMENT

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, December 6, 2005, at 9:00 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners Sam J. Ervin, IV, and James Y. Kerr, II

APPEARANCES:

For Enviracon Utilities, Inc.:

Odes L. Stroupe, Jr., Bode, Call & Stroupe, L.L.P., Attorneys at Law, 3105 Glenwood Avenue, Suite 300, Raleigh, North Carolina 27612

For Island Beach & Racquet Club Condominium Owners Association, Inc.:

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

For GR&S Atlantic Beach, LLC:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Attorneys at Law, 2626 Glenwood Avenue, Suite 560, Raleigh, North Carolina 27608

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 November 8, 2005, Enviracon Utilities, Inc. (Enviracon), filed a petition for approval of an emergency special assessment of ratepayers and/or to discontinue service and requested the Commission to set this matter for an expedited hearing. On November 17, 2005, Enviracon filed an amendment to its petition for approval of a surcharge to pay certain non-capital expenses.

Petitions to Intervene were filed by Enviracon's two customers, Island Beach and Racquet Club Condominium Owners Association, Inc. (IBRC), on November 21, 2005, and GR&S Atlantic

Beach, LLC (GR&S), which owns the Sheraton Atlantic Beach Oceanfront Hotel (Sheraton), on November 30, 2005. IBRC's petition to intervene included a request that the North Carolina Department of Environment and Natural Resources, Division of Water Quality (DENR), be determined to be a necessary party and joined in this proceeding. At the December 6, 2005, hearing, the Commission ruled that both petitions to intervene were allowed and that the request to join DENR as a party to this proceeding was denied.

On November 22, 2005, the Commission issued an Order Scheduling Expedited Hearing, Establishing Filing Deadlines and Prescribing Hearing Procedures.

As required by the Commission's Order, on December 2, 2005, Enviracon filed the testimony of its Vice President, John Chapman; IBRC filed the testimony of its Property Manager, Colton Carawan; the Sheraton filed the testimony of Alfred Frazzini and H. William Hull, Jr.; and the Public Staff filed the testimony of Jerry H. Tweed, Utilities Engineer with its Water and Sewer Division. As further required by the Commission's Order, on December 5, 2005, each of the parties filed statements of their positions and appropriate lists of witnesses.

The hearing was held as scheduled, with each of the above witnesses presenting testimony and Enviracon presenting two rebuttal witnesses, Gary C. Ribblett, P.E., with Delta Environmental Consultants, Inc. (Delta), and Stanley Buck, with Enviracon Beach Operations, Inc. (EBO).

Based upon the foregoing, the evidence presented at the hearing, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT

Parties

1. Enviracon is a North Carolina corporation authorized to provide wastewater treatment service as a public utility subject to the jurisdiction of the Commission. Enviracon is owned by James Proctor and John Chapman.

2. GR&S is a Delaware limited liability company and the owner of the Sheraton.

3. H. William Hull, Jr., is the sole partner and owner of Atlantic Beach Hotel, Limited Partnership (ABH). ABH owned the Sheraton for a number of years, from approximately 1989 until February of 2004. In late February of 2004, ABH sold the Sheraton to GR&S. ABH now owns a 20% interest in GR&S.

4. IBRC is a North Carolina non-profit corporation. The Island Beach & Racquet Club Condominiums consist of 141 condominium units located in Atlantic Beach, North Carolina.

5. The Sheraton and the Island Beach & Racquet Club Condominiums are served by the wastewater treatment plant (WWTP) operated by Enviracon. IBRC and the Sheraton are the only customers served by Enviracon.

6. Enviracon is not engaged in the operation and maintenance of any wastewater utility system other than the one in Atlantic Beach that is the subject of this proceeding.

7. John Chapman, a Grade IV certified wastewater operator, is Enviracon's vice president and chief operating officer and has the responsibility for the day-to-day oversight of this WWTP.

History of Wastewater System

8. The Commission issued the certificate of public convenience and necessity (Certificate) to Enviracon by Commission Order dated November 19, 2004, in Docket No. W-1236, Sub 0. Said Order also canceled Enviracon's emergency operating authority.

9. On May 28, 2004, the Commission issued an Order in Docket No. W-965, Sub 3 (Frit Order), authorizing Frit Environmental, Inc. (Frit), to abandon the system within 60 days of the Order and addressing numerous other capital upgrade issues.

10. As evidenced by the Special Order by Consent (SOC) agreed upon on June 22, 2000, between Frit and the North Carolina Environmental Management Commission and by Enviracon's permit requirements, the wastewater system has not been in compliance with DENR requirements since May 1990, including the period after Enviracon took over as Commission appointed emergency operator from Frit on July 30, 2004.

11. The system was operated by EBO, a certified contract operating company, prior to issuance of the Commission Order (dated July 30, 2004) in Docket Nos. W-965, Sub 4, and W-1236, Sub 0, appointing Enviracon emergency operator of the system in order to "effect an orderly transition to another entity that may acquire the system."

12. Enviracon has continuously utilized EBO to conduct the day-to-day operations of the WWTP. EBO is not an affiliate of Enviracon.

13. Enviracon's operation of the wastewater system has been generally good.

Ownership of Wastewater System

14. The existing WWTP consists of two 50,000 gpd treatment trains, with each train consisting of a series of tanks including a flow equalization tank, a sludge holding tank, an aeration tank, a clarifier tank, tankage associated with filtration, and a chlorine contact/disinfection tank. One of the aeration tanks has collapsed.

15. Enviracon owns only the WWTP and both mechanical rotary sprayers associated with the system. Enviracon obtained those from Frit by bill of sale dated November 19, 2004, after Frit abandoned the plant.

16. Enviracon's permit from DENR, dated July 28, 2004, acknowledges that the wastewater collection facilities are owned by the two customers, with Enviracon being responsible for maintenance and compliance of the wastewater collection facilities.

17. IBRC and the Sheraton own their respective collection systems, including two lift stations, the gravity sewer collection lines, and the force mains that deliver the wastewater from the

customers to the WWTP. Enviracon has no recorded easements for the two lift stations, the gravity sewer collection lines, or the force mains on the property of IBRC and the Sheraton.

18. IBRC owns the land upon which the WWTP and both existing effluent rotary distribution fields are located. The land is leased to the Sheraton, and that lease has been assigned to Enviracon. In addition, the two lift stations involved with this system are located on IBRC's property.

19. The Sheraton owns the land adjoining Lee Drive upon which the new effluent drip-irrigation system is to be located, if approved by DENR. This land has been leased to Enviracon.

20. Both leases (the lease assigned to Enviracon from the Sheraton for the property upon which the WWTP and both existing effluent rotary distribution fields are located and the lease from the Sheraton to Enviracon for the land upon which the new effluent drip-irrigation system is to be located, if approved by DENR) contain termination clauses that are triggered once wastewater utility service is available to the Sheraton and IBRC from the Town of Atlantic Beach.

21. Enviracon owns only a portion of the wastewater system (i.e., the WWTP and the effluent rotary distributors). None of this equipment has any realistic salvage value, as the cost of removal would exceed the fair-market value.

Commission Order – May 28, 2004 – Docket No. W-956, Sub 3 (Frit Order)
and Stipulation and Settlement Agreement

22. In Docket No. W-965, Sub 3, a Stipulation dated May 7, 2004, and Settlement Agreement was executed between IBRC and the Sheraton, whereby they agreed to the escrowing of funds ($50,000 by IBRC and $200,000 by the Sheraton) for capital improvements necessary to bring the facility into compliance and to entry of an order allowing Frit's Petition to Abandon. The Sheraton agreed to pay 100% of the costs above $50,000 to bring the wastewater system into compliance. The Settlement Agreement and Stipulation contemplated the probability that Enviracon, which was then Frit's contract operator, becoming the successor franchise holder and DENR permittee for the wastewater system and making the required improvements using the escrowed funds.

23. The Frit Order required IBRC to escrow and pay a total of $50,000 toward catch-up maintenance expenses and the capital costs of bringing the system into compliance and required the Sheraton to escrow $200,000 and pay all other catch-up maintenance expenses and capital costs needed to bring the system into compliance.

24. The Frit Order and the associated Stipulation and Settlement Agreement between the Sheraton and IBRC provided that, after the system was brought into compliance and a new permit issued to a successor operator, future costs would be allocated 60% to the Sheraton and 40% to IBRC.

Position of IBRC

25. IBRC took the following position in this proceeding:

a) As provided in the Stipulation, the Settlement Agreement, and the Frit Order, IBRC should pay only $50,000 for the capital improvements to bring the wastewater system into compliance, with the Sheraton paying all the remaining costs.

b) IBRC should pay none of the costs to repair or replace the collapsed tank, environmental clean-up costs, pump-and-haul costs, and treatment costs, as the WWTP had never been brought into compliance, as specified in the Stipulation and Settlement Agreement. These costs, if payable by a customer, should be paid by the Sheraton.

c) IBRC should pay none of the costs of the damage claims by the adjoining mobile home park property owners, as it is not appropriate for a utility's customers to be responsible for these types of claims.

Position of the Sheraton

26. The Sheraton took the following position in this proceeding:

a) Based upon the Stipulation and the Settlement Agreement, the Sheraton would pay 100% of the remaining costs to bring the wastewater system into compliance after the IBRC's $50,000.

b) Should the Commission order the customers to pay any of the costs related to the tank collapse, then the Sheraton should pay 60% with IBRC paying 40%, based upon the historical and future cost-allocation methodology.

c) The Sheraton should pay none of the costs for the claims for damages by the adjoining mobile home park property owners, as it is not appropriate for a utility's customers to be responsible for these types of claims.

Capital Improvements to Bring System into Compliance

27. The capital improvements required by the SOC executed June 22, 2000, between Frit and the North Carolina Environmental Management Commission were the relocation/replacement of rotary distributor No. 1, the repair/replacement of the tertiary filter system, the installation of monitoring wells, and the submission of a remedial action plan to eliminate noncompliant groundwater conditions.

28. The known, DENR-required, capital improvements at the time of the Settlement Agreement and Stipulation would have been either those required by the SOC or the improvements required by Enviracon's DENR permit dated July 28, 2004, which was in the draft stage at the time of the Settlement Agreement and Stipulation.

29. There is an outstanding amount owed to Delta[1] of $47,792, for engineering evaluations and for design and plan submittals to bring the system into compliance with the requirements of the July 28, 2004 DENR permit issued to Enviracon, the Settlement Agreement, and the Stipulation.

30. The capital improvements required by the July 28, 2004 DENR permit to Enviracon were the repair or replacement of the flow splitter box, the repair of the arm of the larger rotary distributor, the repair of the larger rotary distributor so that long-term ponding does not continue, the provision of additional influent flow-equalization volume, the replacement of the tertiary filtration unit, and the replacement, including successful abandonment, of rotary distributor No. 1. During the review process for these improvements, DENR pointed out to Enviracon the possible need for further capital expenditures for nutrient removal.

31. Chapman Exhibit D (Items 29-35) reflects an estimated cost associated with the DENR-required improvements to bring the system into compliance, including the replacement of rotary distributor No. 1 field, the equalization basin addition, the tertiary filter replacement, and the nutrient removal system, to be $604,000, plus an outstanding amount owed to Delta of $47,792 (see Footnote No. 1, herein).

32. Enviracon hired Delta to perform the engineering services required to obtain DENR approval of the required system upgrades to bring the system into compliance.

33. Delta performed the required engineering service, including work relating to additional flow-equalization tank capacity, the replacement of the filtration system, and the relocation of the rotary distributor (subsequently changed to installation of a drip-irrigation system in lieu of relocating the rotary distributor No. 1).

34. Substantially all of the engineering work required for permitting by DENR, excluding a potential nutrient removal requirement, has been completed by Delta.

<u>Failure of Existing Escrow Account Process</u>

35. Due to a change in scope of the work, including the design of a drip-irrigation system instead of the relocation of rotary distributor No. 1, Delta charged significantly more than was originally estimated to design the DENR-required improvements ($93,000 as opposed to original estimate of $63,000). Delta has not been paid for services since February of 2005, and in August of 2005 withdrew from the project (see Footnote No. 1, herein).

36. The Sheraton only paid $150,000 of the required $200,000 into the escrow account and IBRC has not made any payment into the escrow account.

[1] On February 8, 2006, the Sheraton filed a Notice of Payment and Request for Assurances of Access and Cooperation Necessary to Facilitate Funding and Work. The Sheraton indicated that it intended to pay Delta's outstanding invoices of $47,792 out of escrowed funds for completed engineering work related to bringing the WWTP into compliance. On March 7, 2006, the Commission issued an Order Conditionally Approving Request. The Commission does not know if Delta has yet been paid. However, if Delta has been paid, any reference to paying Delta contained in this Order shall be considered moot (i.e., Delta shall not be paid twice).

37. The Sheraton and IBRC, without notifying the Commission or obtaining Commission approval, verbally modified the Settlement Agreement so that the Sheraton would pay only $150,000 into the escrow account and, once this $150,000 was paid out, the Sheraton would pay $50,000 into the escrow account and IBRC would pay its $50,000 into the escrow account.

38. The Settlement Agreement escrow account established in the Stipulation and the Frit Order has not resulted in timely payment for the engineering work needed to bring the system into compliance. As a result, the engineering work has stopped.

Tank Collapse – August 3, 2005

39. The WWTP aeration tank wall collapsed on August 3, 2005, as a result of the failure of welding at certain joints. This welding was performed prior to Enviracon's operation and ownership of the WWTP.

40. The collapse of the WWTP tank was the result of failed welding on the original construction of the WWTP and was not related to the improvements contemplated by the Settlement Agreement and Stipulation between IBRC and the Sheraton, as approved in Docket No. W-965, Sub 3.

41. After the tank collapse on August 3, 2005, it was necessary for Enviracon to clean-up the partially treated wastewater that was spilled. Hepaco was the primary contractor for the environmental clean-up.

42. After the tank collapse, DENR required Enviracon to pump-and-haul all the wastewater coming to the WWTP until the remaining tank was tested, reinforced, and certified to be structurally sound by a professional engineer. After the remaining tank was returned to service, it was periodically necessary to pump-and-haul wastewater when the flows to the WWTP exceeded the remaining capacity of 50,000 gpd. This occurred through Labor Day weekend of 2005.

43. Pump-and-haul consists of pumping the untreated wastewater out of the lift station near the WWTP into a tanker truck and transporting the wastewater to a DENR approved WWTP, where it is dumped. Enviracon utilized the Morehead City municipal WWTP for this purpose.

44. When the tank collapsed on August 3, 2005, much of the partially treated wastewater spilled onto the ground and flowed into the adjoining mobile home park (damaging approximately 11 mobile homes and other property). All the owners of this damaged property have made claims against Enviracon.

45. Prior to the collapse of the tank, the treatment capacity of the WWTP was approximately 100,000 gpd. The collapse reduced the capacity to 50,000 gpd, This is significantly less than the typical summertime flows from the two customers.

46. The collapsed tank must be replaced in order to bring the WWTP capacity back to 100,000 gpd. The replacement could consist of major renovations to the existing collapsed tank or the installation of a replacement tank.

47. Enviracon estimated that it would take six months to replace the collapsed aeration tank once a replacement plan was approved and funding provided.

Enviracon's Financial Nonviability

48. The peak usage season for the wastewater system begins sometime in the month of May. At that time, the flows from GR&S and IBRC will exceed the 50,000 gpd capacity of the existing WWTP, resulting in the need for expensive pump-and-haul activities for flows exceeding 50,000 gpd.

49. All the vendors that have not been paid for their previous work (including emergency contractors at the WWTP) have refused to provide further service until paid.

50. Enviracon estimated future costs of approximately $1,700,000 for 35 separate line items: (1) to bring the system into compliance with DENR's requirements as ordered in Docket No. W-965 Sub 3, (2) to pay vendors for the cost of the emergency clean-up and repairs associated with the tank collapse and pump-and-haul activities, (3) estimated costs associated with replacing the collapsed tank, and (4) third-party claims associated with damage to persons and property at the adjoining mobile home park.

51. For 2004, Enviracon's operating losses were $23,380. The operating losses for January 2005 through October 2005 were $7,979, exclusive of all the unpaid expenses resulting from the tank collapse on August 3, 2005.

52. The Sheraton (although now current on its monthly wastewater utility service bills from Enviracon) has a long history of significant arrearages in payments to both Frit and Enviracon.

53. Enviracon does not have any casualty or liability insurance for the WWTP or wastewater system. The Sheraton, although it has various insurance policies, stated its policies do not cover the collapse of the WWTP or the resulting claims of third parties.

54. The Sheraton and IBRC each have stated that they definitely intend to connect to a municipal wastewater system, when and if one becomes available.

Enviracon's Commission-Required Bond

55. The Irrevocable Letter of Credit securing Enviracon's $50,000 bond expired on August 1, 2005, and has not yet been replaced.

Expenses Related to Tank Collapse

56. Pump-and-haul activities during 2005 were initially performed at a cost of $0.11 per gallon. The cost of such activities was later reduced to $100 per hour ($2,400 per day) for each hauling truck on standby for transporting wastewater to Morehead City. There was an additional charge for Morehead City to accept the wastewater into its WWTP (over $20,000 for 4 weeks in 2005).

57. The amount of unpaid invoices associated with the response to the tank collapse, including the emergency renovations to the WWTP and environmental clean-up, pump-and-haul activities, and wastewater treatment by Morehead City, is approximately $350,000.

EVIDENCE AND CONCLUSIONS

Parties

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1 THROUGH 7

The evidence supporting these findings of fact is contained in the testimony of Enviracon witness Chapman and Sheraton witness Hull. This evidence is uncontroverted.

Enviracon witness John Chapman testified that he and James Proctor are the owners of Enviracon. Witness Chapman further testified that he is Enviracon's vice president and chief operating officer and has the responsibility for the day-to-day oversight of this WWTP. He testified that he is a Grade IV certified wastewater operator and is licensed to operate any wastewater plant in North Carolina. He further testified that the WWTP at Atlantic Beach serving IBRC and the Sheraton is the only wastewater treatment system owned or operated by Enviracon.

Sheraton witness Hull testified that he has a personal interest in this docket, as sole partner in ABH, since ABH owns 20% of GR&S. However, witness Hull denied that he now has any control or authority over the management of the Sheraton or GR&S, or that he has any role with respect to GR&S's dealings with outside vendors, except that he reviews and approves or declines to approve the payment of Delta invoices. Witness Hull further testified that he has an indemnity agreement with GR&S under which he will indemnify GR&S for costs incurred to bring the WWTP into compliance pursuant to the Stipulation and Settlement Agreement.

History of Wastewater System

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 8, 9, AND 10

The evidence supporting these findings of fact is contained in the records of the Commission and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 11 AND 12

The evidence supporting these findings of fact is contained in the testimony of Enviracon witnesses Chapman and Buck.

The owners of Enviracon previously owned an interest in EBO, but sold their interest to the operators of EBO after they established Enviracon.

Enviracon is not engaged in the operation and maintenance of any other wastewater treatment system other than the WWTP in Atlantic Beach that is the subject of this proceeding. Despite Enviracon's owners having previous ties with EBO, Enviracon is not an affiliate of EBO.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony of IBRC witness Carawan, Sheraton witnesses Hull and Frazzini, and Enviracon witness Chapman.

IBRC witness Carawan testified that the service provided by Enviracon since it took over the system has been generally good. He testified upon cross-examination that he had had no problems with Enviracon's operation of the system.

The Sheraton witnesses Hull and Frazzini both testified regarding disagreements between Enviracon and the Sheraton after the tank collapse. The disagreements related to Enviracon's requests that the Sheraton fund future pump-and-haul activities and also fund the operation of the lift stations for the purpose of avoiding pump-and-haul operations.

There was no evidence presented by any witness that Enviracon's operations in any way caused the tank collapse. Enviracon witness Chapman testified that Enviracon did not in any way participate in the original construction of the WWTP or the expansion in 1990. Witness Chapman also testified extensively regarding Enviracon's clean-up and pump-and-haul operations after the tank collapse.

The Commission concludes that Enviracon's operation of the wastewater system has been generally good. Enviracon acted responsibly during the post-collapse clean-up and the pump-and-haul operations, and continuously maintained utility service to the customers. The Commission realizes that Enviracon's lack of ownership of the collection system has materially contributed to the inability to resolve the disagreements between the Sheraton and Enviracon regarding the operation of the lift stations and the pump-and-haul activities.

Ownership of Wastewater System

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 14 THROUGH 21

The evidence supporting these findings of fact is contained in the testimony of Enviracon witness Chapman, Public Staff witness Tweed, IBRC witness Carawan, and Sheraton witness Hull.

The record reflects that Enviracon does not own the land upon which the WWTP or effluent disposal systems are located or the collection systems serving the two customers. DENR's July 28, 2004 permit to Enviracon acknowledges that the wastewater collection facilities are owned by the two customers, with Enviracon being responsible for the collection systems' maintenance and compliance.

Witness Carawan explained in his testimony that the wastewater system in question was originally designed to accommodate IBRC only, until a point in time when the condominium market bottomed out and the developer opted to sell the land to permit the development of the Sheraton. At that point, ownership of the WWTP was transferred to the owners of the Sheraton, and the WWTP was located on land leased to the Sheraton by IBRC. The Sheraton subsequently transferred the WWTP and assigned the lease to Enviracon. Enviracon owns the WWTP located on the land.

Witness Chapman testified that, if Enviracon is to be responsible for the collection system, Enviracon should own it. Public Staff witness Tweed agreed with this assessment, and testified that, under normal circumstances, the owner of the WWTP also owns the collection lines and lift stations. Witness Tweed further testified that the potential for problems is great when the utility does not own the collection system. Witness Tweed also testified that, if Enviracon does not obtain ownership of the collection system, then the collection system should be permitted to the two individual owners/customers (IBRC and the Sheraton). He stated that it is the Public Staff's preference that the utility company own the collection system and also hold the DENR permit for the system.

Sheraton witness Hull and IBRC witness Carawan both testified that each is strongly committed to connecting to a municipal wastewater system when and if one becomes available in the Town of Atlantic Beach. Pursuant to a series of agreements and conveyances executed in 1989 and 1990, ABH acquired the WWTP and the land on which it is situated. ABH then conveyed the site to IBRC, and IBRC leased it back to ABH on April 30, 1990, for an indefinite term (as specified in Page 1, Paragraph 2, of the lease), until a public wastewater system became available (Carawan Exhibit No. 3). ABH transferred the WWTP and assigned the lease to Frit, conditioned upon the WWTP being in compliance with DENR Non-Discharge Permit No. WQ000986. A more complete description of these events can be found in Docket No. W-965, Sub 3.

<u>Commission Order – May 28, 2004 – Docket No. W-956, Sub 3 (Frit Order)</u>
<u>and Stipulation and Settlement Agreement</u>

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 22 THROUGH 24

The evidence supporting these findings of fact is contained in the application, the testimony of virtually all of the witnesses in this Docket, and in the record of the Frit abandonment case in Docket No. W-965, Sub 3, of which the Commission hereby takes judicial notice. These findings are primarily jurisdictional and informational and are not contested.

The record of this wastewater system reflects that it has for some time been in need of significant capital improvements, and that generally the Sheraton has agreed to fund those improvements. There is a difference of opinion between the two customers, pursuant to their Settlement Agreement in Docket No. W-965, Sub, 3, as to how much financial burden each would have to bear for future improvements requiring financial expenditures.

The language, based upon the Stipulation, contained in the Frit Order relating to sharing of costs between the two customers, is as follows:

> IBRC and ABH/GR&S have reached agreement on funding of the costs of bringing the wastewater treatment plant located on IBRC property (the Frit facility) into compliance with DENR's requirements. . . .
>
> IBRC and ABH/GR&S have agreed to escrow $250,000 to fund necessary work with the express understanding that the $250,000 is not a cap on the amount that may be needed to be spent to bring the Frit facility into compliance. . . .
>
> IBRC will pay a total of $50,000 toward catch-up maintenance expenses and the capital costs of bringing the system into compliance for issuance of a permit (the

shared costs) to a successor operator by DENR. IBRC will have no further obligation whatsoever to pay any part of any other catch-up maintenance expenses or capital costs of bringing the system into compliance for issuance of a permit to a successor operator. The Sheraton will pay all other catch-up maintenance expenses and capital costs of bringing the system into compliance for issuance of a permit to the successor operator. . . .

The Sheraton will be solely responsible for the cost of moving and reinstalling existing Rotary No. 1 to the Lee Drive property as required by DENR, installing monitoring wells at the Lee Drive property as required by DENR, and any required remediation as to any remaining noncompliant groundwater conditions at the existing site of Rotary No. 1 caused by operation of that rotary. . . .

After the system is brought into compliance and a new permit issued to a successor operator, future costs will be allocated between the Parties on a 60/40 ratio for ratemaking purposes unless the Commission determines there has been a material change in relative usages. . . .

In that case the Commission ordered:

IBRC shall escrow and pay a total of $50,000 toward catch-up maintenance expenses and the capital costs of bringing the system into compliance for issuance of a permit to a successor operator of the system by DENR. ABH/GR&S shall escrow $200,000 and pay all other catch-up maintenance expenses and capital costs of bringing the system into compliance for issuance of a permit to the successor operator.

After the Frit facility is brought into compliance and a new permit is issued to a successor operator, future costs shall be allocated between ABH/GR&S and IBRC on a 60/40 ratio respectively for ratemaking purposes, unless the Commission determines there has been a material change in relative usages.

<u>Position of IBRC</u>

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the testimony of IBRC witness Carawan, the only witness who testified regarding IBRC's positions on the issues. IBRC's position on the issues was uncontroverted.

<u>Position of the Sheraton</u>

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding of fact is contained in the testimony of Sheraton witnesses Hull and Frazzini, who both testified regarding the Sheraton's positions on these issues. Their testimony was uncontroverted.

Capital Improvements to Bring System into Compliance

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 27 THROUGH 34

The evidence supporting these findings is found in the testimony of Enviracon witnesses Chapman and Ribblett, Sheraton witnesses Hull and Frazzini, IBRC witness Carawan, and Public Staff witness Tweed.

The record in this case and in Docket No. W-965, Sub 3, reflects that there was a SOC between DENR and Frit dated June 22, 2000. The basic terms of the SOC were incorporated into the DENR permit issued to Enviracon on July 28, 2004. The requirements of the SOC provided for the relocation/replacement of rotary distributor No. 1, the repair/replacement of the tertiary filter system, the installation of monitoring wells, the submittal of a remedial action plan to eliminate noncompliant groundwater conditions, and the maintenance of the facilities to minimize the impact of the groundwater contamination. The requirements of the permit issued to Enviracon required the repair or replacement of the flow splitter box, the repair of the arm of the larger rotary distributor, the repair of the larger rotary distributor so that long-term ponding does not continue, the provision of additional influent flow equalization volume, the replacement of the tertiary filtration unit, and the replacement of rotary distributor No. 1, including successful abandonment of the existing rotary distributor.

The record reflects that, prior to the collapse of the tank, the plans for improvements mandated by DENR were progressing, with Delta coordinating that effort and submitting invoices primarily to the Sheraton for approval and payment from the escrow fund controlled by the Sheraton and IBRC. During the progression of the plan submittal and approval process, it was determined that relocation of rotary distributor No. 1 was not practical and that a drip-irrigation effluent disposal system would be more appropriate. Furthermore, based upon the results of studies relating to the planning of the drip-irrigation effluent disposal system, DENR expressed concern that consideration should be given to adding a nutrient removal system to the treatment process.

Enviracon witness Chapman Exhibit D (Items 29-35) reflects an estimated cost associated with the DENR-required improvements (including the rotary field replacement, the equalization basin addition, the tertiary filter replacement and the nutrient removal system) of $604,000. The exhibit also reflects (Item 26) an outstanding amount owed to Delta for engineering work, including preparation of plans and specifications and submittal of those plans and specifications to DENR, of $47,792. The testimony of witness Ribblett and the witnesses for Sheraton reflect that the Sheraton refused to approve payment of these invoices from the escrow account because the Sheraton believed the engineering fees were significantly exceeding the original estimated engineering costs. The record further reflects that Delta stopped work on the project in August 2005 due to nonpayment of invoices dating back to February 2005.

The record reflects that Enviracon had no control over the release of funds from escrow for payment of bills. Furthermore, Enviracon does not own the collection systems serving the two customers or the land upon which the wastewater treatment plant or effluent disposal systems are located, and the two customers testified it was their absolute intent to connect to a municipal system when and if one became available. At such time as that occurs, land owned by the customers and currently used for wastewater treatment at the WWTP and disposal activities would revert to the customers. Such a connection would further leave Enviracon holding only the WWTP and the aged rotary distributor. It would likely cost more to remove this equipment than any potential salvage value derived from removal.

The Commission concludes that the two customers exercise considerable control over the system and that, under the current circumstances, it is unlikely that any investor other than the two customers would be willing to invest in the system. The Commission is further of the opinion that, ideally, Enviracon should be given more control (ownership of the collection system, WWTP property, etc.) or, in the alternative, that a mechanism that reduces the existing degree of customer control over the system should be created.

The Commission further concludes that the $47,792 balance of engineering fees owed to Delta (see Footnote No. 1, herein) was incurred in good faith and should be paid from the escrow account established in Docket No. W-965 Sub 3 (or from the escrow account established by this Order).

Failure of Existing Escrow Process

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 35 THROUGH 38

The evidence supporting these findings of fact is contained in the testimony of Enviracon witnesses Chapman and Ribblett, IBRC witness Carawan, Sheraton witnesses Hull and Frazzini, and Public Staff witness Tweed.

Enviracon witness Chapman testified that Enviracon had no approval authority over the payment from the escrow account of invoices. He testified that the Sheraton and IBRC had joint approval authority. He also stated that he believed all of Delta's invoices should be paid and had so advised the Sheraton and IBRC.

IBRC witness Carawan testified that he reviewed and approved the payment of all the Delta invoices, which he then sent to the Sheraton for payment. IBRC's witness Carawan stated that he was not aware that Delta had not been paid for the engineering invoices beyond February 2005 (see Footnote No. 1, herein).

IBRC witness Hull explained that, at the time Enviracon engaged Delta, the estimate Delta gave for the total fees for the design work was $63,000. He stated that Delta's billings totaled approximately $93,000, of which $45,356 had been paid from escrow. He further commented that he refused to approve the remaining invoices, totaling approximately $47,792, because he was concerned about the escalation in the engineering fees beyond the original estimate (see Footnote No. 1, herein).

Witness Hull testified under cross-examination that the drip-irrigation system was a modification from the originally planned work upon which the $63,000 estimate was based and that there were other additions, including engineering evaluations and design work. William Hull also observed on cross-examination that he had an indemnity agreement. Therefore, he is obligated to GR&S for the costs of the improvements to bring the system into compliance as stated in the Stipulation and Settlement Agreement.

Witness Ribblett, a professional engineer, summarized Delta's services performed and the changes in the project which necessitated the increased fees. He stated that additional work was necessary for the evaluation and design of a drip-irrigation system, the application for the pump-and-haul permit from DENR, evaluation of other sites for drip-irrigation in lieu of the Sheraton's Lee Drive property, the nutrient removal system which DENR was considering adding as a requirement, and alternative routes for lines to the drip-irrigation system.

The Commission concludes that the existing escrow procedure has materially contributed to the failure to bring the system into compliance as ordered in the Commission's May 28, 2004, Order. Neither the Sheraton nor IBRC has paid the ordered escrow amounts (see Footnote No. 1, herein). The Sheraton refused to approve and pay Delta's legitimate engineering invoices, which resulted in a total work stoppage by Delta in August 2005. The fact that William Hull had authority to approve and disapprove the engineering invoices, and that he also had an agreement to indemnify GR&S for the costs to bring the system into compliance, has materially contributed to the nonpayment of the engineering invoices and the total work stoppage.

This system is now out of compliance and has been out of compliance continuously since May 18, 1990. The Commission, in Ordering Paragraph No. 4 of its Frit Order, stated the Commission would exercise its jurisdiction to ensure that IBRC and the Sheraton would comply with the Settlement Agreement and Stipulation, which included the construction of the improvements needed to bring the system into compliance. The Commission concludes that the entire existing balance of approximately $92,000 in the escrow account should be paid into a Public Staff-supervised escrow account and that the Public Staff should immediately authorize payment of Delta's outstanding balance of $47,792 (see Footnote No. 1, herein). The remaining escrow balance of approximately $44,208 ($92,000 less $47,792) should be retained in this Public Staff-supervised escrow account pending further order of the Commission.

<u>Tank Collapse – August 3, 2005</u>

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 39 AND 40

The evidence supporting this finding of fact is contained in the testimony of Enviracon witness Chapman, the only witness who presented evidence regarding the cause of the tank collapse.

Witness Chapman testified that all the post-collapse analyses and inspections indicated that the collapse had been caused by faulty welds at joints and that there was virtually no way this could have been visually discovered prior to the collapse (the welds were covered by paint and submerged in wastewater). He testified on cross-examination that the faulty welds related back to the original construction. He stated that the thickness of the metal on the tank was very good. He further explained that, due to a weak joint, stress due to ordinary hydrostatic pressure caused the sudden failure of the tank.

No other party presented evidence concerning the cause of the collapse of the WWTP tank. The Commission concludes the WWTP tank collapsed due to the failure of welded joints at one or more locations. The faulty welding occurred prior to Enviracon's operation and ownership of the WWTP.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 41 THROUGH 47

The evidence supporting this finding of fact is contained in the testimony of Enviracon witness Chapman and Public Staff witness Tweed. This evidence was uncontroverted.

Enviracon's Financial Nonviability

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48

The evidence supporting this finding of fact is contained in the testimony of Enviracon witness Chapman and Public Staff witness Tweed. This evidence was uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 49 THROUGH 51

The evidence supporting these findings of fact is contained in the testimony of Enviracon witness Chapman.

The evidence was uncontroverted that all the vendors who have not been paid for services performed at the WWTP have refused to provide further services. Enviracon witness Chapman testified that Delta withdrew from the project in August 2005 due to nonpayment. He also testified that none of the vendors that participated in the tank collapse environmental clean-up, pump-and-haul activities, WWTP testing and renovations, or wastewater treatment process have been paid, and each has refused to provide further services. These vendors include: Delta (engineering), Hepaco (environmental clean-up), Barnes Environmental, Inc. (pump-and-haul), Lewis Farms and Liquid Waste (pump-and-haul), Morehead City (treatment cost), Stroud Engineering (engineering on WWTP tank integrity), Terracon (ultrasonic testing WWTP), OBI Mechanical, Inc. (WWTP welding renovations), and Unlimited Hauling (tank cleanout). Enviracon witness Chapman testified that only the two governmental agencies have been paid -- DENR was paid \$1,090 for the issuance of the pump-and-haul permit and the Town of Atlantic Beach was paid \$621 for its emergency response.

Enviracon witness Chapman estimated, as shown in Chapman Exhibit D, that a total of \$1,700,000 will be required as follows: (1) to bring the system into compliance with DENR's requirements as ordered in Docket No. W-965 Sub 3, (2) to pay vendors for the cost of the emergency clean-up and repairs associated with the tank collapse and pump-and-haul activities, (3) estimated costs associated with replacing the collapsed tank, and (4) third-party claims associated with damage to persons and property at the adjoining mobile home park. Other parties did not necessarily agree with the correctness of the amounts included in witness Chapman's estimate or agree upon the amount, if any, of the expenses that should be shared by the customers.

Enviracon witness Chapman further testified that Enviracon's 2004 operating loss was \$23,380, as shown on Chapman Exhibit B, and that the January through October 2005 operating loss was \$7,979, as shown on Chapman Exhibit C. He testified that, because Enviracon maintains its accounting records on a cash basis, none of the unpaid invoices relating to the August 3, 2005, tank collapse are included in the 10-month operating loss for 2005. There was no evidence presented by any other parties to dispute Enviracon's operating losses.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence supporting this finding of fact is contained in the testimony of Enviracon witness Chapman, IBRC witness Carawan, and Sheraton witness Frazzini.

Enviracon witness Chapman testified that, since his first experience with the system, payment for utility service by the Sheraton has always run two to three months in arrears. He observed that he cannot shut-off the Sheraton for nonpayment, as Enviracon does not provide the water service, the Sheraton owns its collection system, and Enviracon does not have an easement. He also explained that, if Enviracon did have an easement, it would be difficult and expensive to disconnect service to the Sheraton since extensive digging would be necessary in the difficult sandy soil to physically plug and then later unplug the Sheraton's line. He further noted that at the time of the filing of Enviracon's application on November 8, 2005, the Sheraton was three months in arrears.

IBRC witness Carawan testified that the Sheraton became as much as $70,000 in arrears in its monthly payments to Frit, which meant the Sheraton went 17 months without making a payment to Frit. Witness Carawan further stated that, for the past 15 years, the present and past owners of the Sheraton have delayed and defaulted on one agreement after another.

Sheraton witness Frazzini testified that, when he learned of the Sheraton's monthly service arrearage, he caused the bills to be paid immediately through wire transfer. He further stated that he has instructed the hotel operator on site to pay the monthly wastewater bills in a timely manner and that arrearages are unacceptable.

The Commission concludes that, until recently, the Sheraton has consistently been substantially in arrears in the payment of its monthly wastewater service bills. These consistent arrearages have materially affected the financial viability of the respective wastewater utilities, both Frit and Enviracon. Although the Sheraton now indicates that its payments will be made in a timely manner, the Sheraton only recently became current in these payments, despite the fact that GR&S has owned the Sheraton since February 2004, a period of almost two years. The Commission believes that the Sheraton's history of nonpayment and/or severely delayed payment has substantially contributed to the current and possibly future nonviability of the wastewater utility system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

The evidence supporting this finding of fact is contained in the testimony of Enviracon witness Chapman, IBRC witness Carawan, and Sheraton witness Frazzini.

IBRC witness Carawan testified that the April 30, 1990, lease between IBRC and ABH for the land upon which the WWTP is located required the Sheraton to maintain liability and casualty insurance naming IBRC as an additional insured party. He testified that "IBRC has been informed that the required insurance was not in force at the date of the collapse."

Enviracon witness Chapman testified that Enviracon has never had any insurance for the WWTP or wastewater system. He explained that Enviracon had attempted to obtain insurance from several companies prior to the collapse, but each insurance company declined to issue a policy.

Sheraton witness Frazzini testified that the Sheraton did not have any insurance at the time of the collapse of the WWTP or the property upon which the WWTP is located. He testified that the Sheraton made a claim on its lead insurance carrier, but that the claim was denied.

The Commission concludes that there was not any known liability or casualty insurance covering the WWTP or the land upon which the WWTP is located at the time of the August 3, 2005, tank collapse. The issue of which party was responsible for maintaining such insurance is currently before the General Court of Justice in Carteret County, and the Commission specifically makes no findings or conclusions on this issue.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 54

The evidence supporting this finding of fact is contained in the testimony of Sheraton witness Hull and IBRC witness Carawan, who testified that the Sheraton and IBRC are both strongly committed to connecting to a municipal wastewater system when and if one becomes available in the Town of Atlantic Beach.

Enviracon's Commission-Required Bond

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 55

The evidence supporting this finding of fact is contained in the testimony of Enviracon witness Chapman, IBRC witness Carawan, and Public Staff witness Tweed.

Public Staff witness Tweed testified that, on October 18, 2004, Enviracon filed with the Commission a $50,000 bond secured by an Irrevocable Letter of Credit from RBC Centura. He further testified that this Irrevocable Letter of Credit expired on August 1, 2005, two days before the WWTP collapse. This Irrevocable Letter of Credit has not been renewed or replaced.

Enviracon witness Chapman testified that he had personally put up $50,000 in stock to obtain the letter of credit from RBC Centura and that he had not received notice from RBC Centura that the letter of credit was not going to be renewed. There is no evidence in the record of this proceeding as to Enviracon's intention or ability to replace the surety on its $50,000 bond.

Public Staff witness Tweed recommended that Enviracon be required to file with the Commission a replacement Irrevocable Letter of Credit to secure the existing bond filed on October 18, 2004. In the alternative, witness Tweed recommended that Enviracon file a replacement $50,000 bond secured with sufficient surety as required by GS 62-110.3(a). Witness Tweed recommended that the bond and surety filing should be completed as soon as possible, and that this should be done prior to the payment of any assessment or surcharge by IBRC or the Sheraton.

IBRC witness Carawan testified that IBRC objects to Enviracon's alternative application to discontinue service without its bond being called.

The Commission concludes that G.S. 62-110.3(a) and Commission Rule R10-24(d) require the bond to be secured by sufficient surety, as approved by the Commission. Although Enviracon's $50,000 bond filed with the Commission on October 18, 2004, remains in place, this bond is no longer secured by sufficient surety, as required by G.S. 62-110.3(a) and Commission Rule R10-24(d).

G.S. 62-110.3(d) states that the bond is only forfeitable upon the appointment of an emergency operator, either by the Superior Court in accordance with G.S. 62-118(a) or by the Commission with the consent of the owner or operator. Enviracon has not consented to the appointment of an emergency operator and the Commission does not now intend to ask the Superior Court to appoint an emergency operator pursuant to G.S. 62-110.3(d). There was no evidence presented that a qualified person or entity would be agreeable to serve as an emergency operator or would be able to serve in that capacity successfully based upon the condition of this system.

The Commission concludes that Enviracon should reestablish its bond and surety at a level of $10,000 within 30 days after the effective date of this Order and should increase its bond and surety to a level of $50,000 within 30 days after the restoration of the WWTP to 100,000 gpd and completion of the DENR-required improvements.

Expenses Related to Tank Collapse

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 56 AND 57

The evidence supporting these findings is contained in the testimony of all of the witnesses in this proceeding, but primarily in the testimony of Enviracon witness Chapman.

The evidence reflects that a number of vendors responded to Enviracon's emergency requests for assistance immediately after the collapse of the WWTP tank. The costs associated with this event included those related to pump-and-haul of the untreated wastewater coming to the WWTP, analyzing and stabilizing the remaining usable wastewater treatment facilities, the environmental clean-up of the spilled partially treated wastewater, and other costs directly associated with response to the tank collapse. As reflected on witness Chapman Exhibit D, the following are outstanding invoices associated with those costs:

Hepaco – environmental clean-up cost	$123,993
Barnes Environmental – pump-and-haul cost	31,970
Lewis Farms – pump-and-haul cost	19,596
Morehead City – wastewater treatment cost	20,115
Stroud Engineering – safety certification of remaining tank	1,391
Terracon Engineering – tank ultrasonic testing	21,737
OBI Mechanical – tank modifications, including welding	85,157
Town of Atlantic Beach – emergency response	621
Boyette/Stroupe – legal costs	7,320
TOTAL	$311,900

The Commission notes that the estimated legal costs shown on Chapman Exhibit D were $40,000, with the invoiced amount at that time being $7,320. This appears to be the only outstanding item that was subject to significant change and would increase the total outstanding amount associated with the tank collapse once the final legal invoices are presented.

SUMMARY DISCUSSION AND CONCLUSIONS

The Commission's decision in this matter is governed by G.S. 62-118. Section 62-118(a) provides, in part:

> Upon finding that public convenience and necessity are no longer served, or that there is no reasonable probability of a public utility realizing sufficient revenue from a service to meet its expenses, the Commission shall have power, after petition and notice, to authorize by order any public utility to abandon or reduce such service.

Section 62-118(c) provides further that:

> Whenever the Commission, upon complaint or investigation upon its own motion, finds that the facilities being used to furnish water or sewer utility service are inadequate to such an extent that an emergency (as defined in G.S. 62-118(b) above) exists, and further finds that 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 shall have the power, after notice and hearing, to authorize by order that such service be abandoned or reduced to those customers who are unwilling or unable to advance their fair share of the capital necessary for such improvements.

Lastly, an emergency is defined in 62-118(b) as "the imminent danger of losing adequate water or sewer utility service or the actual loss thereof."

Enviracon, in its Petition in this matter, requested that the Commission impose an emergency special assessment on Enviracon's customers or, alternatively, that the Commission allow Enviracon to abandon service to its customers. Enviracon witness Chapman testified that, due to operating losses, he has personally guaranteed two loans for Enviracon, one for \$20,000 and another for approximately \$12,900, and that both lines of credit are exhausted. He further testified that he talked to several lending institutions and that he could not obtain additional loans for Enviracon without using his personal capital. He explained that the lending institutions advised him that they would not take the WWTP as collateral. He also represented that he does not have personal capital for collateral for a \$1.0 million loan.

Public Staff witness Tweed testified that, without the applied for assessment and surcharge, Enviracon could not possibly rebuild the collapsed treatment tank or obtain needed services to operate the system in the future. He observed that the unpaid contractors and vendors who worked on the collapsed tank, environmental clean-up, and pump-and-haul activities have refused to provide further services unless paid.

There is no doubt that the failure of one of the treatment tanks at the WWTP has created an emergency, because the remaining tank is not capable of treating the volume of wastewater anticipated during the summer season. Moreover, without appropriate relief, Enviracon is not able to obtain pump-and-haul service to compensate for the loss of the tank. The evidence amply demonstrates that Enviracon cannot obtain the capital necessary to replace the collapsed tank from any source other than its two customers. Under G.S. 62-118(c), however, the Commission is limited in its ability to assess Enviracon's customers, and may only require such customers to advance "the capital necessary to improve or replace the [inadequate] facilities." Neither G.S. 62-118(c) nor the prohibition against prospective recovery of prior unexpected expenses, State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977), allow the Commission to impose a surcharge on customers for operating expenses previously incurred by the utility and not recovered through rates. Thus, even were the Commission to impose a surcharge upon the Sheraton and IBRC for the capital expenditures necessary to replace the failed tank, without the means to authorize Enviracon to recover from its customers funds sufficient to pay the additional clean-up and pump-and-haul expenses incurred as a result of the tank failure, the Commission must conclude that there is no reasonable probability of Enviracon realizing sufficient revenue to meet its expenses. The Commission, therefore, concludes that Enviracon should be allowed to abandon service to its customers pursuant to G.S. 62-118(a) unless the customers consent to making the payments described below.

The parties took differing positions as to whether Enviracon should continue to operate the system. For example, Public Staff witness Tweed posed the possibility of the customers either establishing their own utility systems or jointly owning the entire system without regulation by the Commission. He testified that it is difficult to see the benefit of Commission regulation in this situation and that deregulation by the Commission should be seen as a viable alternative. On the other hand, IBRC and the Sheraton indicated in their respective proposed orders a preference for a utility operating the WWTP system as compared to their own operation of the system. Likewise, Enviracon stated a preference for continuing to be the holder of the certificate of public convenience and necessity for the system. Among the reasons cited for not turning over the operation of the utility to the customers are the inability of the two customers to agree upon much of anything and the difficulty of splitting the system so that each customer could operate its own independent wastewater treatment system without having to cooperate with the other customer.

The possibility of another utility acquiring this wastewater system is virtually nonexistent. The Commission requires that a utility seeking to acquire a water or wastewater utility system demonstrate managerial, operational, and financial viability. It is inconceivable that any such viable utility would desire to acquire this wastewater system with: (a) its lengthy noncompliance history; (b) the substantial capital improvements needed; (c) the collapsed tank catastrophe; (d) the high probability of extensive pump-and-haul activities during the summer of 2006; (e) the poor payment history by the Sheraton; (f) the inability to disconnect the Sheraton for nonpayment; (g) the fact that the utility only owns the WWTP and the aged rotary distributors; (h) the fact that the utility does not own the collection system and lift stations; and (i) the fact that the only two customers have expressed a strong intent to connect to a municipal wastewater system as soon as it becomes available, thereby enabling IBRC to regain the land upon which the WWTP and rotary distributors are located and the Sheraton to regain the Lee Drive property planned to be used for the drip-irrigation system.

In an attempt to accommodate the apparent desire of the parties to retain Enviracon as the franchised public utility authorized to operate the WWTP, the Commission will not authorize abandonment at this time provided that the Sheraton and IBRC agree, in writing, to pay, in addition to the capital costs necessary to comply with the SOC and to bring the WWTP into compliance with DENR requirements as agreed to by the parties in the Stipulation previously approved by the Commission: (1) the capital costs necessary to repair the WWTP as a result of the tank collapse and return it to full capacity; and (2) the expenses related to the environmental clean-up, pump-and-haul activities, wastewater treatment by Morehead City, and Enviracon's associated attorney's fees in accordance with the payment plan outlined below. Assuming that the Sheraton and IBRC agree to make these payments as described in this Order, the Commission will refrain from authorizing abandonment at this time.

IBRC has taken the position in this proceeding that, pursuant to the Settlement Agreement, it is only responsible for a total of $50,000 toward capital improvements and catch-up maintenance, including the collapse of the WWTP. The Sheraton has taken the position that any costs associated with the collapse of the WWTP should be shared between the parties to this proceeding. The Public Staff supports a 60/40 sharing of the plant collapse costs between the two customers, as the collapse could not have been contemplated by the Settlement Agreement, Stipulation, or the Frit Order.

Based upon the record in this proceeding and the record in Docket No. W-965, Sub 3, the Commission concludes that the Settlement Agreement and the Frit Order did not contemplate any significant expenditures outside those reflected in the SOC and July 28, 2004 permit. While, as alleged by IBRC, the system has never been brought into full compliance with the requirements of DENR, all of the requirements for compliance as listed in the SOC and the July 28, 2004 permit could have been completed and still would not have likely prevented the collapse of the WWTP wall, which was caused by faulty welding. Therefore, the Commission concludes that, the two customers should agree to share the capital costs necessary to replace the failed tank on a 60/40 basis, which represents the approximate flow allocation between the two customers[1].

With regard to the environmental clean-up, pump-and-haul, and wastewater treatment expenses incurred as a result of the tank failure, the Commission believes that all of these costs were incurred in good faith in response to an emergency situation. The vendors acted in a responsible manner to an emergency situation involving a Commission regulated system, which within the past year had been under the control of an emergency operator reporting directly to the Commission. The Commission is further persuaded that the customers should be required, as a condition for continuing to receive utility service from Enviracon, to reimburse Enviracon for its reasonable attorney's fees associated with the current proceeding. The Commission, therefore, further concludes that, as a condition for continuing to receive service from Enviracon and for the Commission to refrain from authorizing abandonment, the two customers should agree to pay, in four-equal monthly installments, a total of $350,000 for payment of the above vendor invoices and attorney's fees into the Public Staff-supervised escrow account describe below. As noted with regard to these costs, IBRC should agree to pay $140,000 (40%) and the Sheraton $210,000 (60%).

All parties expressed a desire for the Commission to establish a Public Staff-supervised escrow account to receive and disburse funds paid to cover the costs addressed in this Order, with all invoices to be audited by the Public Staff and Commission approval required of all disbursements. The Commission agrees that that such an arrangement is preferable, and concludes that the existing escrow account has not worked satisfactorily. Therefore, upon agreement of the parties to proceed, the balance in the existing escrow account of approximately $92,000 shall be immediately transferred

[1] The Sheraton indicated in its filing (Notice of Payment and Request for Assurances of Access and Cooperation Necessary to Facilitate Funding and Work) on February 8, 2006, that it wished to proceed with installing replacement facilities due to the upcoming Summer 2006 season. The Public Staff should review the cost estimates and/or invoices regarding this work and recommend to the Commission amounts to be paid into the Public Staff-supervised escrow account by the Sheraton and IBRC in order to pay for this work. To the extent that the Sheraton advanced payments to vendors for this work outside of the Public Staff-supervised escrow account, the Public Staff should recommend payments to the Public Staff-supervised escrow account by IBRC in order to ensure a 60/40 sharing of these expenditures.

to a Public Staff-supervised interest bearing escrow account[1]. These funds shall be used to pay the existing Delta outstanding balance of $47,792 (see Footnote No. 1, herein), with the remaining funds to be used only for capital expenditures to bring the wastewater system into compliance as stated in the Stipulation, Settlement Agreement, and Frit Order. In addition, funds paid by the Sheraton and IBRC pursuant to their agreement to fund the capital costs necessary to replace the collapsed WWTP tank, to fund the work necessary to bring the system into compliance with applicable DENR requirements over and above the amount that has already been escrowed, and to pay the expenses incurred for environmental clean-up, pump-and-haul operations, wastewater treatment by Morehead City, and attorney's fees shall be paid into this escrow account.

The Public Staff shall audit all invoices and provide copies of the invoices and the Public Staff's audit report and recommendations to Enviracon, IBRC, and the Sheraton. These three parties should have a period of up to 10 business days within which to file written comments prior to the Commission's evaluation of the Public Staff's recommendations. Upon evaluation of the audit report, the Public Staff's recommendations, and the comments of Enviracon, IBRC, and the Sheraton, the Commission will determine whether it is appropriate to approve the requested disbursement and, if so, the appropriate amount of disbursement.

Exhibit D attached to Enviracon witness Chapman's testimony lists numerous items (10 through 21) associated with damage to the mobile home park adjoining the WWTP property. The collapse of the tank caused wastewater to flow into the mobile home park, causing damage which has resulted in numerous claims by the affected mobile homeowners. These type of costs would normally be covered by the utility's insurance. However, Enviracon stated that it was unable to obtain insurance, and has requested assessments upon its customers to cover these third-party damage claims.

The Commission concludes that Enviracon's customers should not be required to pay these third-party damage claims against the utility. Utility companies should protect themselves from this type of liability, and the failure to do so does not automatically transfer the burden to the customers. For the Commission to rule in favor of Enviracon on this issue is not justified and would set an unacceptable precedent in the regulation of utility companies. The Commission, therefore, concludes that the customers should not be required to pay for the mobile home park damage claims.

Accordingly, the Commission is of the opinion that Enviracon should be allowed to abandon wastewater service to the Sheraton and IBRC unless each customer files, within seven days of the date of this Order, a written agreement to pay into a Public Staff-supervised escrow account (1) the entire balance of the escrow account established by the Frit Order ($200,000 from the Sheraton plus $50,000 from IBRC, less proceeds paid out for appropriate DENR required improvements); (2) in four-equal monthly payments (beginning 30 days after the date of this Order and repeating at 60 days, 90 days, and 120 days after the date of the Order), its proportionate share of the estimated $350,000 of non-capital expenses incurred for environmental clean-up, pump-and-haul, wastewater treatment by Morehead City, and attorney's fees; and (3) the other payments required by the terms of this Order and the earlier Stipulation, Settlement Agreement, and Frit Order, with the monies involved in this last category of payments to be provided within ten days of a request by the Public Staff for payment. The Commission is further of the opinion that the balance of the Frit Order escrow account (including

[1] Within seven days of the date of this Order, the Public Staff should file its recommendations regarding the details of this Public Staff-supervised escrow account (i.e., in whose name is the account set up, who signs checks, is a co-signer required, who releases signer to issue a check, what are the reporting requirements, and other details, as necessary)

the funds previously withheld by the Sheraton and IBRC) should be transferred to the Public Staff-supervised escrow account within 15 days of the date of this Order. Failure by either customer to comply with these requirements will result, upon further petition by Enviracon, in a Commission Order allowing Enviracon to abandon the WWTP.

According to Finding of Fact No. 31, the $250,000 deposited into the original escrow account will likely not be sufficient to bring the system into compliance with DENR requirements. The Public Staff should file, within 60 days of the date of this Order, its recommendation regarding the amount and schedule of additional funds that the Sheraton must pay into the Public Staff-supervised escrow account.

The Commission is concerned that, even without the tank collapse event, Enviracon was having cash flow problems due to insufficient revenues to cover ongoing expenses. Additionally, the Commission notes that, until the WWTP is restored to its former capacity (100,000 gpd), there will likely be significant expenses related to pump-and-haul activities during the summer season (Memorial Day to Labor Day). These expenses cannot possibly be covered under the current rates. The Commission requests that the Public Staff meet with Enviracon and its customers to address this issue and recommend, if necessary, revisions to Enviracon's tariff that will cure the revenue shortfall, including the submission of a request for any needed interim rates.

Lastly, as noted herein, the Commission will not require the customers to pay the third-party claims against Enviracon for uninsured damages incurred in the mobile home park as a result of the tank collapse. However, without taking a position on the merits of the insurance issue, the Commission believes that it would be in the best long-term interest of the customers if they would provide funds to ensure that Enviracon is able to resolve such third-party claims. Otherwise, Enviracon may not be able to continue to operate even with the other relief granted in this Order.

IT IS THEREFORE, ORDERED as follows:

1. That Enviracon shall be authorized to abandon wastewater service to its customers unless:

a. Each customer files, within seven days of the date of this Order, a written agreement to pay into a Public Staff-supervised escrow account (1) the entire balance of the escrow account established by the Frit Order ($200,000 from the Sheraton plus $50,000 from IBRC, less proceeds paid out for appropriate DENR required improvements); (2) in four equal monthly payments (beginning 30 days after the date of this Order and repeating at 60 days, 90 days, and 120 days after the date of the Order), its proportionate share of the estimated $350,000 of non-capital expenses incurred for environmental clean-up, pump-and-haul, wastewater treatment by Morehead City, and attorney's fees; and (3) the other payments required by the terms of this Order and the earlier Stipulation, Settlement Agreement, and Frit Order, with monies involved in this last category of payments to be provided within ten days of a request by the Public Staff for payment; and

b. Beginning 30 days after the date of this Order (and repeating at 60 days, 90 days, and 120 days after the date of this Order), the Sheraton shall deposit $52,500 into the Public Staff-supervised escrow account and IBRC shall deposit $35,000 into the Public Staff-supervised escrow account.

Failure by either customer to comply with these requirements will result, upon further petition by Enviracon, in a Commission Order allowing Enviracon to abandon the WWTP.

2. That, upon agreement by Enviracon's customers of the conditions imposed herein and compliance therewith,

a. The vendors, after Public Staff audit of their invoices and final approval by the Commission, shall be paid the approved amounts. Copies of all invoices shall be submitted to the two customers for 10 business days for comment prior to approval for payment by the Commission.

b. The Public Staff is requested to meet with Enviracon and the customers to address the issue of potential revenue shortfalls during ongoing WWTP operation (and especially during pump-and-haul activities) and recommend, if necessary, revisions to Enviracon's tariff that will curtail the revenue shortfall.

c. Enviracon shall reestablish its bond and surety at a level of $10,000 within 30 days after the date of this Order.

d. Enviracon shall increase its bond and surety to a level of $50,000 within 30 days after the restoration of the WWTP to 100,000 gpd and completion of the DENR-required improvements.

e. That Enviracon shall complete one of the attached bonds (Appendices A-1, A-2, or A-3) and <u>return said bond to the Commission</u>. Additionally:

i. If the bond selected is Appendix A-1, the Applicant shall deposit the appropriate surety in the amount of $10,000 with SunTrust Bank, Attention: Rebecca Brock, Trust Administrator, 4101 Lake Boone Trail, Suite 111, Raleigh, North Carolina 27607.

ii. If the bond selected is Appendix A-2, the Applicant shall file the letter of credit surety and commitment letter (see Filing Requirements for Bonding, Appendix A-4) with the Commission. The letter of credit shall contain the following language <u>verbatim</u>:

> If for any reason the Letter of Credit is not to be renewed upon its expiration, the Bank shall, at least 60 days prior to the expiration date of the Letter of Credit, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Letter of Credit will not be renewed beyond the then current maturity date for an additional period. Failure to renew the Letter of Credit shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Letter of Credit to cash and deposit said cash proceeds with the administrator of the Commission's bonding program. Said cash proceeds from the

converted Letter of Credit shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e).

iii. If the bond selected is Appendix A-3, the Applicant shall file the power of attorney and commitment letter (see Filing Requirements for Bonding, Appendix A-4) with the Commission.

3. That $47,792 from the escrow account established pursuant to the Frit Order shall be paid to Delta (see Footnote No. 1, herein) for engineering services rendered.

4. That the balance of the Frit Order escrow account (including the funds previously withheld by the Sheraton and IBRC) shall be transferred to the Public Staff-supervised escrow account within 15 days of the date of this Order.

5. That the Public Staff is requested to file, within seven days of the date of this Order, its recommendations regarding the details of the Public Staff-supervised escrow account (i.e., in whose name is the account set up, who signs checks, is a co-signer required, who releases signer to issue a check, what are the reporting requirements, and other details, as necessary).

6. That the Public Staff is requested to file, within 60 days of the date of this Order, its recommendation regarding the amount and schedule of additional funds that the Sheraton must pay into the Public Staff-supervised escrow account for completion of bringing the system into compliance with DENR requirements.

7. That the Public Staff is requested to review the cost estimates and/or invoices regarding this work and recommend to the Commission amounts to be paid into the Public Staff-supervised escrow account by the Sheraton and IBRC in order to pay for this work. To the extent that the Sheraton may advance payments to vendors for this work outside of the Public Staff-supervised escrow account, the Public Staff is requested to recommend payments to the Public Staff-supervised escrow account by IBRC in order to ensure a 60/40 sharing of these expenditures.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of April, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

rb040506.01

NCUC DOCKET NO. W-1236, SUB 1 APPENDIX A-1

BOND

______________________________ of ______________________,
(Name of Utility) (City)
______________________, as Principal, is bound to the State of North
(State)
Carolina in the sum of ______________________________
______________________________ Dollars ($____________)
and for which payment to be made, the Principal by this bond binds himself, his, and its successors and assigns.

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water or sewer utility ______________
____
(describe utility)
____ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in G.S. § 62-110.3, and Commission Rules R7-37 and/or R10-24, and,

WHEREAS, the Principal has delivered to the Commission ______________________
____
(description of security)
with an endorsement as required by the Commission, and,

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, this bond shall become effective on the date executed by the Principal, and shall continue from year to year unless the obligations of the Principal under this bond are expressly released by the Commission in writing.

NOW THEREFORE, the Principal consents to the conditions of this Bond and agrees to be bound by them.

This the ____________ day of ____________________ 20____.

____
(Name)

NCUC DOCKET NO. W-1236, SUB 1 APPENDIX A-2

BOND

____ of _________________________,
(Name of Utility) (City)
______________________________, as Principal, is bound to the State of North
(State)
Carolina in the sum of ________________________________
______________ Dollars ($____________) and for which payment to be made, the Principal by this bond binds _________________________ and ____________ successors and assigns.
(himself)(itself) (his)(its)

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water and/or sewer utility ____________
____
(describe utility)
____ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water and/or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in G.S. § 62-110.3, and Commission Rules R7-37 and/or R10-24, and

WHEREAS, the Principal has delivered to the Commission an Irrevocable Letter of Credit from
____
(Name of Bank)
with an endorsement as required by the Commission, and,

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, if for any reason, the Irrevocable Letter of Credit is not to be renewed upon its expiration, the Bank shall, at least 60 days prior to the expiration date of the Irrevocable Letter of Credit, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Irrevocable Letter of Credit will not be renewed beyond the then current maturity date for an additional period, and

WHEREAS, failure to renew the Irrevocable Letter of Credit shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Irrevocable Letter of Credit to cash and deposit said cash proceeds with the administrator of the Commission's bonding program, and

WHEREAS, said cash proceeds from the converted Irrevocable Letter of Credit shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e), and

WHEREAS, this bond shall become effective on the date executed by the Principal, and shall continue from year to year unless the obligations of the Principal under this bond are expressly released by the Commission in writing.

NOW THEREFORE, the Principal consents to the conditions of this Bond and agrees to be bound by them.

This the ____________ day of ____________________ 20___.

____
(Principal)

BY: ___________________________

NCUC DOCKET NO. W-1236, SUB 1 APPENDIX A-3

BOND

_________________________ of ____________________, ____________________,
(Name of Utility) (City) (State)
as Principal, and ____________________, a corporation created and existing under
(Name of Surety)
the laws of ______________________________, as Surety (hereinafter called "Surety"), are
(State)
bound to the State of North Carolina in the sum of ______________ Dollars ($__________) and for which payment to be made, the Principal and Surety by this bond bind themselves and their successors and assigns.

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water and/or sewer utility ____________
____
(Describe utility)
____ and;

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water and/or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in § 62-110.3, and Commission Rules R7-37 and/or R10-24, and

WHEREAS, the Principal and Surety have delivered to the Commission a Surety Bond with an endorsement as required by the Commission, and

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, if for any reason, the Surety Bond is not to be renewed upon its expiration, the Surety shall, at least 60 days prior to the expiration date of the Surety Bond, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Surety Bond will not be renewed beyond the then current maturity date for an additional period, and

WHEREAS, failure to renew the Surety Bond shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Surety Bond to cash and deposit said cash proceeds with the administrator of the Commission's bonding program, and

WHEREAS, said cash proceeds from the converted Surety Bond shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e), and

WHEREAS, this bond shall become effective on the date executed by the Principal, for an initial ________________ year term, and shall be automatically renewed for additional __________
(No. of Years) (No. of Years)
year terms, unless the obligations of the principal under this bond are expressly released by the Commission in writing.

NOW, THEREFORE, the Principal and Surety consent to the conditions of this bond and agree to be bound by them.

This the ____________ day of ______________________ 20___.

____
(Principal)

BY: ___________________________

____
(Corporate Surety)

BY: ___________________________

APPENDIX A-4

Filing Requirements for Bonding

Type of Bond

	Cash / Certificate of Deposit Bond	Irrevocable Letter of Credit Bond	Commercial Surety Bond
Bond A-1	X 1/		
Bond A-2		X 1/	
Bond A-3			X 1/
Cash / CD	X 2/		
Letter of Credit		X 3/	
Power of Attorney			X 4/
Commitment Letter		X 5/	X 5/

(To be filed with the Chief Clerk - where applicable)

1/ Original Copy of the Bond - Preferably on the forms prescribed in the Commission Order dated July 19, 1994, in Docket No. W-100, Sub 5 (Bond forms are usually attached to Order Requiring Bond for each specific franchise).

2/ Notification from SunTrust Bank (SunTrust is the Commission's custodian for bond sureties) that cash or CD surety has been received for a given bond.

3/ Original Copy of Non-Perpetual Irrevocable Letter of Credit [Letter of Credit must comply with Rule R7-37 New Section (e)(4) as adopted by the Commission in its Order dated July 19, 1994, In Docket No. W-100, Sub 5.]

4/ Original Copy of Power of Attorney for individual who signed Appendix A-3 as Corporate Surety

5/ Original Copy of Commitment Letter

(a) This letter need only contain a statement indicating whether the utility is required to pledge utility company assets (collateral and type) to secure the bond or irrevocable letter of credit; and

(b) The premium paid by the utility (if any) to the bank and/or lending institution for their accommodation of the borrower.

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 ALLOWING DISCONNECTION OF IBRC

BY THE COMMISSION: On April 26, 2006, Enviracon Utilities, Inc. (Eviracon) filed a notice that it intended to discontinue Island Beach and Racquet Club's sewer utility service for failure to pay its monthly utility bill since January 2006. On April 28, 2006, Island Beach and Racquet Club Condominium Owner's Association, Inc. (IBRC) filed a reply to Enviracon stating that it had paid its monthly bills into an escrow account managed by its attorney. IBRC further stated that, if Enviracon entered upon IBRC's property without its permission, Enviracon would be subject to trespass charges.

On May 4, 2006, Enviracon filed a petition asking the Commission to authorize it to discontinue IBRC's sewer utility service, to affirm Enviracon's right to enter onto IBRC's property for the purpose of discontinuing utility service, and to grant a tariff revision allowing Enviracon to charge actual cost for disconnecting and reconnecting utility service. Enviracon's currently approved reconnection charge is $15.00. On May 11, 2006, IBRC filed a Protest regarding Enviracon's May 4, 2006, filing. IBRC stated its reasons for making payments into an escrow account instead of to Enviracon and stated its belief that the rate increase for reconnection to be actual cost was not lawful upon the record. On May 16, 2006, Enviracon filed a Response to IBRC's Protest. Enviracon took exception to IBRC's reasons for escrowing its payments and noted that the requested change in its reconnection charge was not a general rate increase; but a tariff adjustment not unlike other tariff adjustments that the Commission authorizes from time to time.

On May 17, 2006, the Public Staff filed comments addressing, among other things, the disconnection issue. On May 17, 2006, the Commission scheduled the matter for oral argument on May 22, 2006 to address the Petition to Discontinue Service and any other outstanding issues. The oral argument was subsequently rescheduled for May 25, 2006.

On May 25, 2006, the Commission heard extensive oral argument from the Applicant, the Public Staff, GR&S Atlantic Beach, LLC (GR&S), owner of the Sheraton Hotel in Atlantic Beach, and IBRC about the issues outstanding in this docket and Docket No. W-1236, Sub 2, Enviracon's request for rate relief. While all the issues raised by the parties are important and will be addressed by this Commission, this Commission must act expeditiously to ensure Enviracon's financial viability so that it can continue to provide wastewater treatment for its only two customers, GR&S and IBRC, and the residents and guests that will utilize the customers' facilities during the peak tourist season which began on Memorial Day weekend. For that reason, this Order will only address the following: (1) Enviracon's request to disconnect service to IBRC for nonpayment of service;

(2) Enviracon's request for Commission authorization to enter upon the property of IBRC to disconnect service; and (3) Enviracon's request to change its reconnection charge to reflect the actual cost to reconnect service if service is cut off for good cause. With the exception of Enviracon's request for rate relief, which has been addressed today by separate order in Docket No. W-1236, Sub 2, the other issues outstanding between the parties shall be considered and addressed in a later order of this Commission.

In support of its position, Enviracon asserted that OBI Mechanical, Inc. (OBI), the main contractor working to reinforce and provide the required certification of the surviving wastewater treatment tank, was owed approximately $85,157, for which it filed a lien in Carteret County Superior Court on December 29, 2005, against IBRC and Enviracon. Since such filing, IBRC has taken the position that it is entitled to escrow the monthly payments for wastewater treatment services provided to it by Enviracon. Therefore, IBRC has escrowed in an account under its control all monthly payments that would have gone to Enviracon since January of 2006, which presently approximates some $10,267. Enviracon would normally utilize those funds to support current operations. Consequently, Enviracon has applied to this Commission to discontinue service as a result of nonpayment. IBRC opposes Enviracon's request on the grounds that, were it to make payment directly to Enviracon, it would be subjecting itself to potential duplicative liability to OBI. According to IBRC, its monthly payments to Enviracon may be "funds...owed to the contractor which arise out of the improvement on which [OBI] worked or furnished materials." G.S. 44A-18(1). In addition, IBRC argues that, since Enviracon failed to pay OBI, IBRC should be excused from making direct payment to Enviracon under the principle enunciated in Goldston Brothers, Inc. v. Newkirk, 233 N.C. 428, 64 S.E.2d 424(1951), which indicates that a wrongful act or conduct by a party to the contract excuses further performance of the contract by the wronged party.

The Commission is not persuaded that IBRC's action in escrowing these funds owed to Enviracon justifies its failure to make payments to Enviracon. First, the Commission concludes that ordinary payments for utility service are not payments "which arise out of the improvement" on which OBI worked. For that reason, the Commission does not believe that IBRC faces a genuine threat of duplicative liability. Furthermore, there is no claim that Enviracon breached a contract with IBRC or prevented performance by IBRC so as to allow IBRC to refrain from paying Enviracon. On the contrary, the contract by which Enviracon provides utility service is completely separate from the contract under which OBI provided service to Enviracon. As a result, neither of the arguments advanced by IBRC is persuasive.

Under these circumstances, we believe that IBRC is required to make timely payments to Enviracon. Having failed to do so, our rules permit Enviracon, upon timely notice given, to disconnect service. Commission Rule R10-16(c). Enviracon has given IBRC timely notice of disconnection. Moreover, our rules permit Enviracon to access IBRC's property to do so. Commission Rule R10-6 and Rule R10-16(b). By agreeing to receive service from Enviracon, IBRC has implicitly authorized Enviracon to act in accordance with these rules. The Commission therefore concludes that Enviracon is permitted to disconnect service to IBRC within seven days of this Order and that IBRC shall permit Enviracon access to its property to do so unless IBRC pays its bill in full, including late fees, within that time frame.

Further, we conclude that it is reasonable that Enviracon's reconnection fee be changed to reflect the actual cost of reconnection. The only argument that IBRC has advanced in opposition to the proposed change in the reconnection fee is that it lacks adequate support on the present record.

The record describes the efforts that must be undertaken by Enviracon to disconnect a recalcitrant customer. The process was described thusly:

> We've got to go plug pipes, go in manholes, maybe even dig up some stuff. I mean it's not something that's going to be done with a flip of a lever. But we've got to be in a situation where we can do that if a customer is not going to pay its account.
>
> (Tr. p. 23.)

The Commission takes judicial notice that the cost of such activities clearly exceeds $15.00. As a result, the Commission concludes that the proposed reconnection fee should be changed to reflect the actual cost of reconnection.

After fully considering the argument of the parties and the entire record, the Commission is of the opinion that Enviracon's request to disconnect service to IBRC for nonpayment, Enviracon's request for authorization to enter upon the property of IBRC to do so, and Enviracon's request to change its reconnection charge when it disconnects service to reflect the actual cost of disconnection and reconnection should be granted.

In reaching this conclusion, the Commission is mindful that no business, let alone a capital intensive, wastewater treatment facility serving only two customers, can remain viable for long if one customer providing 40% of its operating revenue fails to tender timely and continuous payment for services rendered. By any standard, Enviracon is in dire financial straits as a result of IBRC's nonpayment. Enviracon has rendered the service and IBRC has utilized and continues to utilize the service. Having utilized the service, IBRC must now pay for its use on a timely basis. IBRC has not done so and is subject to disconnection.

IT IS THEREFORE, ORDERED as follows:

1. That Enviracon is permitted to discontinue the wastewater treatment service to IBRC for failure to make the required monthly payments since January, 2006, without the need for further Commission action unless IBRC pays its bill in full, including late fees, within seven days of this Order.

2. That Enviracon is permitted, pursuant to Rule R10-6 and Rule R10-16(b) of the Commission Rules, to go upon the lands owned by IBRC as may be necessary to disconnect the IBRC collection system for purposes of enforcing Enviracon's right to discontinue service to IBRC in an immediate manner.

3. That Enviracon's reconnection charge shall be Enviracon's actual cost to discontinue and later reconnect the wastewater service.

4. That Enviracon shall itemize the estimated cost of disconnecting and reconnecting the service and shall furnish this estimate to the customer with the cutoff notice <u>prior</u> to disconnection.

5. That the Commission's decision regarding other issues raised in this case shall be rendered in a future order on a later date.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of May, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Lh052606.02

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 ADDRESSING MOTIONS FOR RECONSIDERATION AND REQUEST FOR ASSURANCES

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Thursday, May 25, 2006, at 9:30 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Commissioners Lorinzo L. Joyner and James Y. Kerr, II

APPEARANCES:

FOR ENVIRACON UTILITIES, INC.:

Odes L. Stroupe, Jr., Bode, Call & Stroupe, LLP, Post Office Box 6338, Raleigh, North Carolina 27628-6338

FOR ISLAND BEACH AND RACQUET CLUB CONDOMINIUM OWNERS ASSOCIATION, INC.:

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

FOR GR&S ATLANTIC BEACH, LLC:

Daniel C. Higgins, Burns, Day & Presnell, PA., Post Office Box 10867, Raleigh, North Carolina 27605

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 February 8, 2006, GR&S Atlantic Beach LLC (GR&S), owner of the Sheraton Hotel in Atlantic Beach, filed a Notice of Payment and Request for Assurances with the Commission seeking assurance that Island Beach and Racquet Club Condominium Owners Association, Inc. (IBRC) and Enviracon Utilities, Inc. (Enviracon) would cooperate with GR&S's efforts to repair and replace a failed wastewater treatment tank used by Enviracon to provide sewer utility service to IBRC and GR&S. IBRC and GR&S are the only customers of Enviracon. On March 7, 2006, the Commission issued an Order providing GR&S with the assurances that it sought subject to conditions suggested by the Public Staff. On April 6, 2006, IBRC filed Objections to the Order and Petition requesting the Commission to Reconsider the March 7 Order.

On April 7, 2006, the Commission issued an Order Authorizing Surcharge in Lieu of Abandonment. On April 7, 2006, GR&S filed a Second Request for Assurances of Access and Cooperation Necessary to Facilitate Funding and Repairs. GR&S asked that IBRC and Enviracon be ordered to state in writing that they would not oppose or interfere with the efforts of GR&S to replace the failed tank in the wastewater treatment plant (WWTP) and that an order confirming those assurances be issued. On April 8, 2006, Enviracon filed its Response to GR&S's Second Request for Assurances. On April 17, 2006, GR&S filed a Response to the Commission's April 7, 2006, Order Authorizing Surcharge in Lieu of Abandonment in which GR&S accepted the conditions outlined in the April 7 Order subject to the condition that IBRC also accepted them.

On April 26, 2006, Enviracon filed a written notice that Enviracon intended to discontinue IBRC's sewer utility service for failure to pay IBRC's monthly utility usage bill since January 2006. On April 28, 2006, IBRC filed a reply stating that IBRC had paid its monthly bills into an escrow account managed by its attorney. IBRC further stated that, if Enviracon entered upon IBRC's property without its permission, Enviracon would be subject to trespass liability.

On May 4, 2006, Enviracon filed a petition asking the Commission to authorize it to discontinue IBRC's sewer utility service, to affirm Enviracon's right to enter on to IBRC's property for the purpose of discontinuing utility service, and to grant a tariff revision allowing Enviracon to charge actual cost for disconnecting and reconnecting utility service. On May 8, 2006, GR&S filed a Motion for Reconsideration in which it requested that the Commission reconsider several of its findings and modify the April 7 Order accordingly. On May 11, 2006, IBRC filed a Protest regarding Enviracon's May 4, 2006, filing. IBRC explained its reasons for making payments into an escrow account instead of to Enviracon and stated its belief that the rate increase for reconnections was not lawful upon the record. On May 16, 2006, Enviracon filed a Response to IBRC's Protest. Enviracon took exception to IBRC's reasons for escrowing its payments and noted that the requested change in its Reconnection Charge was not a general rate increase, but a tariff adjustment not unlike other tariff revisions the Commission authorizes from time to time.

On May 17, 2006, the Public Staff filed comments regarding many of the issues raised by the other parties.

On May 19, 2006, in Docket No. W-1236, Sub 2, Enviracon filed an Application for Increased Wastewater Rates and Emergency Rates. In the Application, Enviracon requested that the Commission hear the emergency rate aspect of that case on an expedited basis. The Commission granted the request and scheduled that issue, among others, for oral argument on May 25, 2006.

On May 24, 2006, IBRC filed a Protest and Petition to Intervene. On May 25, 2006, the Commission granted IBRC's motion to intervene in Docket No. W-1236, Sub 2. On May 25, 2006, GR&S orally moved to intervene in Docket No. W-1236, Sub 2. GR&S's motion to intervene was granted. The intervention and participation of the Public Staff of the North Carolina Utilities Commission in both dockets has been recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 25, 2006, the Commission heard extensive oral argument from Enviracon, the Public Staff, GR&S, and IBRC about the issues outstanding in Docket Nos. W-1236, Sub 1 and W-1236, Sub 2, Enviracon's request for increased rates. Because of the need to act expeditiously to ensure Enviracon's financial viability, the Commission issued orders on May 31, 2006, in Docket Nos. W-1236, Sub 1 and W-1236, Sub 2, addressing: (1) Enviracon's request to disconnect service to IBRC for nonpayment of service; (2) Enviracon's request for Commission authorization to enter upon the property of IBRC to disconnect service; (3) Enviracon's request to change its reconnection charge to reflect the actual cost to reconnect service if service is disconnected for good cause; and (4) Enviracon's request for emergency rate relief. By those same orders, the Commission deferred ruling on the additional issues raised and argued by the parties until today. The Commission now addresses the remaining issues.

I. <u>GR&S's Motion for Reconsideration</u>

In its May 8, 2006 Motion for Reconsideration, GR&S requested that the Commission reconsider the following decisions made in the April 7 Order: (1) the Commission's conclusion that the Commission was without authority to require IBRC and GR&S to pay, through surcharge, reimbursement for operating expenses incurred by Enviracon that resulted from the collapse of the wastewater treatment tank; (2) the Commission's determination that Enviracon should be allowed to petition the Commission to abandon its certificate upon the failure of IBRC and GR&S to agree in writing to reimburse Enviracon for the expenses resulting from the post tank collapse; (3) the Commission's determination about Enviracon's ability to address and rectify conditions which led to Enviracon's filing of the application to make a special assessment on its customers or to discontinue service; and (4) the Commission's decision to make no findings or conclusions on the issue of which party was responsible for maintaining liability or casualty insurance covering the wastewater treatment plant or the land upon which the wastewater treatment plant was located at the time of the August 3, 2005 tank collapse. In addition to the aforementioned, four additional issues were raised in either the responses or further arguments of the parties during the hearing. These four additional issues, which are consecutively and cumulatively numbered, are: (5) whether a determination by the Carteret County Superior Court that the lease between GR&S and IBRC has been breached by either party to the agreement deprives this Commission of jurisdiction to determine when, to whom, and under what circumstances utility service must be provided by Enviracon; (6) whether, pursuant to G.S. 62-118(c), GR&S is entitled to assert a proprietary interest in the utility system owned and operated by Enviracon; (7) whether the land upon which the wastewater treatment plant and the rotary effluent distributors are located or the lease agreement which permits Enviracon to utilize the land for utility purposes may be transferred without prior written Commission approval; and (8) whether the 60/40 expense allocation should be reconsidered?

The individual claims of GR&S, IBRC, Enviracon, and the Public Staff arising from GR&S' reconsideration motion will now be addressed.

1. <u>The Commission's authority to require IBRC and GR&S to pay a surcharge to reimburse Enviracon for post tank collapse operating expenses</u>

In the April 7, 2006 Order, the Commission concluded that the Commission was without authority in Docket No. W-1236, Sub 1 to require IBRC and GR&S to pay a surcharge to reimburse operating expenses incurred by Enviracon as a result of the tank collapse. In its Motion for Reconsideration, GR&S disagrees with the Commission's conclusion. GR&S argues that:

> Contrary to the Commission's conclusions, the expenses in question have been incurred within the past 12 months, and pursuant to N.C. Gen. Stat. §62-133 and other provisions of Chapter 62, these costs, to the extent reasonable and prudent, are recoverable by Enviracon through its Commission-approved rates and charges. Furthermore, substantial precedent exists that would authorize the Commission to defer these emergency type costs for ratemaking purposes and amortize them through rates over a reasonable period of time. Thus, to the extent the Commission has determined that these expenses were appropriately incurred by Enviracon, the Commission possesses the requisite authority to order and require the customers to reimburse Enviracon for these expenses.

The Public Staff supports GR&S's Motion to Reconsider this issue. IBRC does not.

GR&S's argument is premised upon the Commission's authority to consider the expenses and allow their recovery by Enviracon "through its Commission-approved rates and charges." GR&S' argument overlooks the fact that Docket No. W-1236, Sub 1 is not a rate case. Rather, the proceeding in which the April 7, 2006 Order was issued was a proceeding initiated under G.S. 62-118 to establish a special emergency assessment for Enviracon's customers as a result of extraordinary expenses that occurred because of the tank collapse. Under G.S. 62-118(c), the Commission is limited in its ability to assess Enviracon's customers, and may only require such customers to advance the capital necessary to improve or replace the inadequate facilities. As a result, the Commission is not authorized to impose a surcharge on customers for operating expenses previously incurred and not recovered through rates in a proceeding initiated pursuant to G.S. 62-118.

This Commission, however, is clearly authorized to consider in a rate case whether the expenses in question have been incurred during the test period, and, if so, whether, pursuant to G. S. 62-133 and other provisions of Chapter 62, these costs, to the extent reasonable and prudent, may serve as a basis for Commission-approved prospective rates and charges. Furthermore, substantial precedent exists that would authorize the Commission to defer such extraordinary expenses for ratemaking purposes and allow the utility to amortize such costs through properly established rates over a reasonable period of time. See e.g., <u>In re Duke Power</u>, Docket No. E-7, Sub 776; <u>In re Progress Energy Carolinas</u>, Docket No. E-2, Sub 843.

As noted above, Enviracon has since filed an application for increased wastewater rates and emergency rates in Docket No. W-1236, Sub 2. On May 25, 2006, the Commission heard oral argument on an expedited basis concerning Enviracon's interim rate increase request. On May 31, 2006, in Docket No. W-1236, Sub 2, the Commission declared Enviracon's filing to be a general rate case pursuant to G.S. 62-137; approved a Schedule of Interim Rates; suspended the proposed new rates for up to 270 days pursuant to G.S. 62-134; required Enviracon to file an undertaking to refund not later than 10 days after the date of the Order; and established the 12-month period ending December 31, 2005 as the test period for use in that proceeding.

The Commission now has an appropriate rate-making vehicle in which to examine the expenses that occurred in connection with the tank collapse and, if necessary, to establish prospective rates based upon those expenses. In fact, the Commission has approved interim rates established, at least in part, on the basis of these post tank collapse expenses. As a result, given that the Commission believes that the original determination with respect to this issue was correct and that the result sought by its motion has been achieved by other means, GR&S's motion to reconsider this issue in this docket is denied.

2. Enviracon's ability to abandon its franchise

In its Order of April 7, 2006, the Commission examined Enviracon's service obligation to GR&S and IBRC and concluded that Enviracon would be allowed to abandon its certificate upon the failure of IBRC and GR&S to agree in writing to reimburse Enviracon for the capital costs to be incurred in replacing the collapsed wastewater treatment tank and the expenses resulting from the tank collapse. The Commission reached this conclusion because G.S. 62-118(c) does not allow the Commission to order Enviracon's customers to reimburse Enviracon's extraordinary post tank collapse operating expenses. Since the issuance of the order, GR&S has voluntarily agreed to reimburse Enviracon for both those expenses and the capital costs associated with replacing the tank while IBRC has not. Under the express terms of the Commission's Order, both parties are required to agree. Thus, Enviracon has the right to petition the Commission to abandon service to both GR&S and IBRC under the express terms of the Order. It has not done so. GR&S now requests the Commission to reconsider the conclusion that Enviracon is authorized, upon petition to the Commission, to abandon the franchise to serve GR&S and IBRC if the parties do not agree to the conditions set forth in the April 7 Order.

As noted above, GR&S argues that the Commission, contrary to the Commission's conclusions, is authorized to allow Enviracon to recover operating expenses pursuant to G.S. 62-133 and other provisions of Chapter 62. Further, GR&S argues that, with a rate increase of the type that the Commission has the ability to grant, there would be a "reasonable probability of [Enviracon] realizing sufficient revenue... to meet its expenses." GR&S's argument is thus again premised on the Commission's ability to award a rate increase for operating expenses under G.S. 62-118. The merits of that argument have been addressed in the preceding section of this Order. Suffice it to say, the Commission continues to believe that it does not have authority to order the remedy that GR&S seeks outside of a ratemaking proceeding. That is, under the circumstances that existed when the April 7 Order was issued, the Commission could not require Enviracon's customers to reimburse Enviracon for post tank collapse expenses. For that reason, the finding of fact and supporting conclusions of law which permitted Enviracon to abandon its franchise if both parties did not agree in writing to reimburse Enviracon for the aforesaid expenses were correct when issued.

The Commission is aware, however, that the conditions that existed when the April 7, 2006 order was issued have changed markedly. Among the changes that have occurred since that time was the grant of an interim rate increase on May 31, 2006. The interim rate increase will alleviate some of the financial strain which Enviracon faced that caused this Commission to question its continued viability. In addition, IBRC has forwarded a check to Enviracon for slightly more than $10,000 for payment for past services rendered by Enviracon. Enviracon can utilize these funds to pay its operating expenses and other debts which are necessary for the ongoing provision of service. Finally, GR&S has advanced the funds necessary to repair and replace the collapsed wastewater treatment plant and the plant is now in service.

The Commission did not anticipate such changed conditions when it issued its April 7, 2006 Order. When those changed circumstances are factored into the Commission's decision-making process, the Commission now concludes that an order allowing Enviracon to abandon its service obligation to GR&S would be unjust because GR&S has fully complied not only with the letter of the Commission's Order but also with its spirit. Further, under these circumstances, the Commission cannot, at this time, conclude "that there is no reasonable probability of [Enviracon] realizing sufficient revenue from a service to meet its expenses" *to serve GR&S* as required by G.S. 62-118(a). Without such a finding, the Commission cannot "authorize... [Enviracon] to abandon or reduce such service" *to GR&S*. G.S. 62-118(a). As a result, the portion of the April 7, 2006 Order permitting Enviracon to petition to abandon its service obligation to GR&S is rescinded.

Similarly, the Commission must now also rescind the portion of its finding which allowed Enviracon to petition to abandon service to IBRC *because of Enviracon's inability to realize sufficient revenue from a service to meet its operating expenses for the post tank collapse expenses.* As previously stated, the interim rate relief and payment of escrowed funds by IBRC alleviated much of the Commission's concern with regard to the post tank operating expenses. Thus, conditions now existing permit Enviracon to realize sufficient revenue from a service to meet its post tank operating expenses. Therefore, the conclusion permitting Enviracon to abandon service to IBRC for that reason is hereinafter rescinded.

If the Commission's April 7 Order had only been concerned with Enviracon's inability to deal with the post tank collapse operating expenses, the Commission would also be required to fully rescind its conclusion that Enviracon should be permitted to petition to abandon service to IBRC as the Commission has done with GR&S. However, in addition to the concern about Enviracon's inability to realize sufficient revenues to meet its operating expenses, the April 7 Order also considered Enviracon's *inability to meet its capital needs without an infusion of capital from its customers*. To address this concern, the Commission required GR&S and IBRC to agree pursuant to G. S. 62-118(c) to advance funding to replace and repair the WWTP so that the needs of Enviracon's only two customers, GR&S and IBRC, could be met. The Commission conditioned Enviracon's continued obligation to provide utility service to the parties upon their acceptance of this requirement.

GR&S agreed to the condition and, in fact, advanced the entire cost of repairing and replacing the plant. IBRC declined the Commission's invitation to advance its proportionate share of the capital costs based upon its belief that the amount specified by the Commission is not contemplated in an agreement between GR&S and IBRC. The Commission has fully considered and rejected IBRC's interpretation of said agreements and has been provided with no persuasive argument for changing that result.

It thus appears that IBRC is either unwilling or unable to advance its share of the money that the Commission has determined is fair and necessary for such capital improvements. In such circumstances, the Commission has the power, "after notice and hearing, to authorize by order that such service be abandoned or reduced to those customers who are unwilling or unable to advance their fair share of the capital necessary for such improvements." G.S. 62-118(c). The Commission has taken the first step in this process by authorizing Enviracon to pursue abandonment upon the failure of IBRC to advance such funds. Despite the fact that GR&S has advanced 100% of the cost of replacing the collapsed tank, it is not just and reasonable for IBRC to escape responsibility for paying its fair share of those costs. The Commission now reaffirms the findings of fact and conclusions which permit Enviracon to pursue abandonment for this reason as to IBRC. In theory, the Commission could now order Enviracon to begin the process of abandonment since IBRC has, to date, refused to agree to pay its fair share of the reasonable capital costs. The Commission will, however, refrain from taking such action in order to give IBRC one last opportunity to agree in writing to fund its fair and proportionate share of the capital costs as directed in the April 7, 2006 Order. If IBRC fails to do so within the prescribed time limits, Enviracon is ordered to initiate proceedings before this Commission to abandon service to IBRC.

In completely rescinding the section of the order concerning GR&S and modifying this provision of the order relating to IBRC, the Commission finds as a fact the following:

(a) GR&S has made a binding commitment to fund 60% of the post collapse operating expenses as required by the April 7 Order;
(b) The interim rate increase approved by the Commission in Docket No. W-1236, Sub 2 covers* GR&S's obligation to pay 60% of the post tank collapse expenses established in the April 7, 2006 Order;
(c) These factors adequately address the concern that Enviracon would not be able to cover post tank collapse operating expenses without a 60% contribution by GR&S;
(d) The interim rate increase approved by the Commission in Docket No. W-1236, Sub 2 covers* IBRC's obligation to pay 40% of the post tank collapse expenses established in the April 7, 2006 Order;
(e) This factor adequately addresses the concern that Enviracon would not be able to cover post tank collapse operating expenses without a 40% contribution by IBRC;
(f) GR&S has funded 100% of the capital costs necessary to repair and replace the collapsed tank, a factor which clearly satisfies GR&S's obligation to fund its portion of the capital costs necessary to repair and replace said plant;
(g) IBRC has not agreed to pay the 40% share of capital costs that the Commission determined would be necessary for Enviracon to continue to serve GR&S and IBRC;
(h) The determination that the Commission made as to the proportions that IBRC and GR&S should pay was fair and reasonable and these proportions continue to be fair and reasonable;
(i) IBRC shall pay 40% of the capital costs to replace and repair the collapsed tank and other capital improvements in the manner that the Commission set forth in the April 7, 2006 Order;

* The precise rate necessary to fully recover the post tank operating expenses caused by the collapse of the treatment tank shall be determined in Docket No. W-1236, Sub 2.

(j) In the event that IBRC fails to notify the Commission in writing of its agreement to pay 40% of the capital costs within 10 days of the entry of this Order and to make payment of its fair share of those costs within 30 days of receiving a determination of the amount of IBRC's share of those costs, Enviracon shall initiate proceedings to discontinue service to IBRC; and

(k) The Public Staff shall, to the extent that the capital costs are validated, reimburse GR&S for the share of the capital costs that it advanced in excess of the 60% required by the April 7 Order when and if, such funds are paid by IBRC.

The April 7, 2006 Order is modified accordingly.

3. Enviracon's ability to address and rectify conditions which led to the filing of an application to make a special assessment

In Findings of Fact Nos. 13, 36-38, and 51-52, respectively, and in the Evidence and Conclusions for these Findings of Fact set out in the April 7 Order, the Commission found that Enviracon's non-ownership of components of the sewer collection system, disputes and disagreements over funding of and withdrawal of funds from the Commission-approved escrow account, and the failure of GR&S or its predecessor to at all times be current on its accounts with Enviracon in some way materially contributed to the emergency that Enviracon found itself in. These actions helped precipitate Enviracon's filing of the request for a surcharge and/or to abandon service.

GR&S now requests that the Commission reconsider the findings of fact and conclusions which resulted therefrom because, "[a]t all times addressed by Enviracon's petition, Enviracon had the ability to petition the Commission to address and rectify the alleged conditions mentioned in these findings and conclusions." GR&S Motion for Reconsideration, p. 4. Further, "GR&S requests the Commission to modify its Order to state that Enviracon had access to such remedies, failed to avail itself of them prior to instituting this action and has access to such remedies today, as long as it remains the certificated operator of the public utility facilities." GR&S Motion for Reconsideration, pp. 4-5.

The Public Staff opposes GR&S's modification request by arguing that the legal remedies to which GR&S refers, though technically available, were not practically available against the old Sheraton ownership group. As the Public Staff stated during oral argument:

> They had—legal remedies that they could have pursued, but in all practicality of shutting off sewer service, particularly when you don't have clearly defined easements and digging up sand at the beach and the cost and a $15 reconnect fee instead of—you know, had they been a more experienced utility company, they would have pursued their remedies, but I'm not sure in this case where a company begin[s] as an emergency operator and then become[s] a utility that they really had the background.

Enviracon makes similar arguments in opposition to GR&S's Motion.

Enviracon entered into this utility service arrangement as an inexperienced emergency operator to rescue a "troubled system" that served only two customers, GR&S and IBRC. Enviracon inherited numerous challenges and limitations that have previously been detailed in this and other dockets. The Commission will not repeat that history here. Suffice it to say, these challenges were made more difficult by the complicated ownership of the wastewater treatment plant and the land, which made the utility's customers owners of significant portions of the wastewater treatment infrastructure.

Enviracon had very limited recourse when confronted by any problems caused by GR&S and IBRC. For instance, it could not simply disconnect service when GR&S (or IBRC) did not pay because the fee for reconnection did not cover the costs of reconnection and because the process of disconnection was substantially more complicated than shutting off a valve. Moreover, the customers, as owners of the land and infrastructure, could attempt to restrict access to relevant property and facilities to preclude disconnection despite Commission rules to the contrary. In spite of these challenges, Enviracon's operation of the wastewater treatment system, by all accounts, has been generally good. [Finding of Fact No. 13, April 7, 2006 Order.] For these reasons, the Commission refuses to modify its finding of fact to attribute any blame to Enviracon for this calamity or to mitigate any fault which has been previously assigned to other parties in this proceeding. The Commission denies GR&S's motion to modify these findings of fact and reaffirms the finding that Enviracon's operation of the wastewater treatment system has been generally good. The Commission does, however, note that in recent months GR&S has paid its bills in a timely fashion, commendably stepped forward to provide financing for repair of the collapsed treatment tank, and otherwise acted in an exemplary manner.

4. Responsibility for maintaining liability or casualty insurance covering the wastewater treatment plant at the time of the August 3, 2005 tank collapse

In the April 7, 2006 Order, Finding of Fact No. 53, the Commission found that:

> Enviracon does not have any casualty or liability insurance for the WWTP or wastewater system. The Sheraton, although it has various insurance policies, stated its policies do not cover the collapse of the WWTP or the resulting claims of third parties.

In the discussion of evidence and conclusions for this finding of fact, the Commission stated that "the issue of which party was responsible for maintaining such insurance is currently before the General Court of Justice in Carteret County, and the Commission specifically makes no findings or conclusions on this issue."

GR&S requests that the Commission revisit this issue. In support thereof, GR&S asserts that IBRC has asked the Carteret County Superior Court to declare that the 1990 lease between IBRC and Atlantic Beach Hotel, L. P. (ABH), GR&S's predecessor in interest, is in material default for failure to maintain insurance; that IBRC is entitled to terminate the lease and all assignments of the lease; and that IBRC's success in the civil suit will result in either one of two outcomes: (1) the lease will be terminated and all improvements, including the sewage treatment facilities, will be removed; or (2) GR&S's interest in the lease will be terminated and the plant will be unavailable to provide service to GR&S. GR&S and the Public Staff urge the Commission to exercise jurisdiction over the property upon which the WWTP is located to prevent IBRC from unilaterally extinguishing the rights of GR&S to receive service from the WWTP.

Specifically, the Public Staff requests that the Commission reaffirm that control of the WWTP and rotary effluent distributors and the land upon which they are located cannot be changed without prior written Commission approval pursuant to G.S. 62-111(a). [May 24, 2006 comments of the

Public Staff.] IBRC argues that the Commission does not have jurisdiction to enter an order which precludes IBRC from unilaterally extinguishing the rights of GR&S to receive service from the WWTP should IBRC ultimately be successful in the suit in Superior Court.

The Commission notes that the original Finding of Fact No. 53 and the supporting evidence and conclusions dealt with the narrow issues of whether there was liability or casualty insurance covering the WWTP prior to the collapse and which, if any, party was responsible for maintaining liability or casualty insurance. With regard to the former issue, the Commission held that there was not any known liability or casualty insurance covering the WWTP prior to its collapse. Regarding the second issue of which, if any, party was responsible for maintaining insurance on the WWTP, the Commission, out of deference to the pending proceeding in Superior Court dealing with that issue, declined to address the issue. The Commission did so with the knowledge that Enviracon, the regulated utility, was not a party to the Superior Court proceeding.

By letter dated July 28, 2006, the Honorable Benjamin G. Alford, Judge of the Superior Court, informed GR&S and IBRC that, "[a]fter reviewing all the materials and hearing from you at oral argument in this matter, I have decided to Stay this matter pending the resolution of the matter in the North Carolina Utilities Commission." Presumably, the parties now suggest that the time is ripe for this Commission to determine which party was responsible for maintaining liability insurance. After fully reviewing and considering Judge Alford's letter, the Commission again declines to address the disputed liability insurance issues raised by the lease between GR&S and IBRC because these issues do not directly involve the provision of utility service by Enviracon. Rather, these issues revolve around the parties' damage liability to each other and can be best resolved by the Carteret County Superior Court. At bottom, the Commission believes that it can decide the manner in which utility service is provided and the rates which are charged for that service. However, the other issues between the parties should be decided by the General Court of Justice.

In light of this approach to the present controversy, the Commission will address the following issues raised by the parties in this and other filings which may touch upon the lease <u>and</u> may directly affect the provision of service by a public utility.

5. <u>Disconnection of service in light of provisions of the lease</u>

The Commission has broad powers to regulate public utilities and to compel their operation in accordance with the policy of this State as declared by the General Assembly. <u>Utilities Commission v. Public Staff</u>, 123 N.C. App. 623, 473 S.E.2d 661(1996).

> A public utilities commission generally has exclusive jurisdiction over various matters involving public utilities, such as rates and charges, classifications, and service, effectively denying to all courts except the highest state court jurisdiction over such matters. Thus, once a public utility commission has assumed jurisdiction over a public utility for administering the law applicable to the activities of the utility, the commission has exclusive jurisdiction over the regulation and control of that utility, subject only to review by the courts." 64 Am Jur2d 147.

Enviracon is a regulated public utility subject to the jurisdiction of the Commission. As such, the Commission has broad and comprehensive power to determine not only Enviracon's rates but also when and to whom Enviracon provides service. In exercising this authority, the Commission is limited only by the constraints in the Public Utilities Act, and the State and federal Constitutions. Subject to review by appellate courts, the Commission has the exclusive authority to determine and approve the service territory of a regulated utility and the identities of the customers served by the utility. The utility must, within reason, serve any customer residing within its franchised service territory that desires service provided the customer complies with the rules regarding payment and service. Thus, Enviracon must continue to serve GR&S as long as GR&S complies with the Commission's rules regarding payment and service until Enviracon is relieved of that responsibility by this Commission. Duke Power Co. v. City of High Point, 22 N.C. App. 91, 205 S.E.2d 774(1974). Neither IBRC nor the Superior Court of Carteret County is authorized to compel discontinuance of service to an Enviracon customer who is compliant with the Commission approved tariffs and rules and has fulfilled his or her obligation to the utility.

Moreover, the Commission has exclusive authority to determine whether private agreements entered into with respect to the operation of a public utility shall be recognized and, if necessary, modified or abrogated upon a showing that the contracts do not serve the public interest. Utilities Commission v. Carolina Water Services, Inc., 149 N.C. App. 656, 562 S.E.2d 60(2002). Thus, if necessary, the Commission could modify the lease agreement to prohibit IBRC from unilaterally terminating service to GR&S if GR&S is found to have violated the terms and conditions of the lease upon a showing that the contract does not serve the public interest.

IBRC argues that this Commission does not have such authority in this case because this is an agreement between two private parties. The Commission is not persuaded by this argument. The lease agreement contemplates that the leasehold was to be used by a sewage treatment plant certificated by the North Carolina Utilities Commission. Specifically, the lease states:

> The Lessor hereby leases to Lessee, and the Lessee hereby leases from the Lessor, the Property...for use as the site of or in connection with the operation of a sewage treatment facility to *serve the Sheraton Resort and related facilities and other public utility customers presently served or which it may be required to be served by the North Carolina Utility Commission* or any other regulatory authority in order to maintain a Certificate of Convenience and Necessity or Operating permit to serve the Sheraton Resort ("the Sewage Treatment Facility"). [Emphasis added.]

Once an operator applies for a certificate, and is certificated, to provide the service contemplated by the lease, the lease implicitly, and the statute explicitly, recognizes the Commission's authority to regulate public utilities and to compel their operation in accordance with the policy of this State as declared by the legislature. This authority includes the power to review, recognize, and, if necessary, modify contracts, including the lease agreement, which affect the provision of certificated utility service to the parties to the agreement. This power is exercised exclusively by this Commission. As a result, the Superior Court has no power to order or allow the discontinuance of service by the utility to the party that has breached the agreement even though the Court has the power to determine if the leasehold has been breached. Duke Power Co. v. City of High Point, 22 N.C. App. 91, 205 S.E.2d 774 (1974). Thus, the breach of this lease agreement by GR&S cannot be a basis for the unilateral termination of utility service to GR&S unless the termination is also authorized by the Commission or requested by the customer.

In addition to the aforementioned, IBRC has reserved an ownership interest in the land upon which the WWTP facilities reside and through which the collection and delivery pipes traverse to deliver wastewater for treatment. The reservation of this ownership interest in the land upon which the utility operates, coupled with compensation to the owner and an effort to affect the manner in which utility service is provided or to whom service is provided, may operate to render IBRC a de facto utility. In Utilities Commission v. Buck Island, 162 N.C. App. 588, 592 S.E.2d 244 (2004), the Court of Appeals upheld the Commission's determination that a party to a private agreement with the utility, Buck Island, was also a public utility even though it did not directly sell water and sewer service to the public. In making that determination, the Court of Appeals upheld this Commission's finding that Buck Island owned a twenty-two per cent interest in the backbone facilities used to produce water and treat sewage in two developments, that the existence of these systems facilitated its real estate development activities, that Buck Island received tap fees from purchasers of lots within the developments, and that these factors sufficed to make Buck Island a de facto utility subject to the Commission's jurisdiction.

In this case, IBRC has reserved an ownership interest in the land occupied by the wastewater treatment facilities and accompanying pipes. The availability of adequate sewage treatment facilities enhances IBRC's ability to market condominiums and to lease those condominiums as vacation rentals. Without the availability of adequate sewer treatment, IBRC would not be able to reap the economic benefits that it enjoys as a source of marketable vacation rentals. Nor would IBRC be a desirable or inhabitable ownership option for many of its inhabitants. Clearly, IBRC has an economic interest in the continued provision of wastewater treatment by Enviracon beyond that which inures to a regular consumer of utility service. Moreover, IBRC has an ownership interest in property for the treatment of wastewater, i.e., the land, and further has received economic benefits inuring from the provision of utility service to itself and GR&S. These facts could, upon compliance with proper procedures, suffice to support a finding that IBRC is a de facto utility and subject to extensive Commission regulation. At that point, the Commission would have the authority to authorize continued service of GR&S by Enviracon even if the Superior Court determines that GR&S has breached a leasehold agreement with IBRC by failing to maintain liability and casualty insurance. The Commission does not, at this point, propose to find IBRC to be a de facto utility; however, it will not hesitate to revisit this issue if necessary. Thus, given the Commission's authority over utility operations as described above, the Commission determines that Enviracon must continue to provide service to GR&S and that IBRC cannot use the Superior Court litigation to obtain a different result. The determination of a breach in agreement by the Superior Court does not negate the Commission's exclusive authority to provide for continued service by the utility.

6. GR&S's proprietary interest in the utility system owned and operated by Enviracon pursuant to G.S. 62-118(c)

The parties acknowledge that GR&S has made substantial capital expenditures at its own risk and without prejudice to the rights, claims, defenses or positions of any party in connection with any pending or future litigation to replace and repair the collapsed tank in time to assure service by the beginning of the summer vacation season. GR&S and the Public Staff argue that advancement of capital entitles GR&S to assert a proprietary interest in the utility pursuant to G.S. 62-118(c). IBRC disagrees. IBRC essentially argues that the Commission has not approved the advancement of any capital as required by statute, and, as a result, GR&S is not entitled to assert a proprietary interest in the system.

G.S. 62-118(c) provides:

> Whenever the Commission, upon complaint or investigation upon its own motion, finds that the facilities being used to furnish water or sewer utility service are inadequate to such an extent that an emergency (as defined in G.S. 62-118(b) above) exists, and further finds that 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 shall have the power, after notice and hearing, to authorize by order that such service be abandoned or reduced to those customers who are unwilling or unable to advance their fair share of the capital necessary for such improvements. The amount of capital to be advanced by each customer shall be subject to approval by the Commission, and shall be advanced under such conditions as will enable each customer to retain a proprietary interest in the system to the extent of the capital so advanced.

The statute requires the Commission to approve the amount of capital advanced by each customer and the circumstances under which such capital is advanced. GR&S advanced the entire amount of capital necessary to repair and replace the failed tank without Commission oversight *prior* to securing Commission approval. The Commission is a firm proponent of adhering to procedural rules established by the General Statutes. The Commission is not, however, convinced that, in interpreting and applying those rules, it must allow form to triumph over substance.

All parties to this proceeding are aware of the dire circumstances that resulted from the collapse of the tank. Enviracon was woefully undercapitalized and would have been required to abandon or severely restrict its service if it did not receive an infusion of capital to rebuild the plant. Enviracon could not have sustained another season of pump and haul operations or covered any additional costs resulting from insufficient capacity caused by the collapse of this tank. Needed vendors would not assist Enviracon without assurance of payment. GR&S, at its own risk, stepped forward and advanced the capital necessary to repair and replace the tank. [During oral argument, GR&S represented that it had spent $268,000 and anticipated that its total expenditures would exceed $450,000.] IBRC did not.

In circumstances such as those herein described, substance should triumph over form. In the Commission's view, GR&S advanced capital that Enviracon did not have and could not obtain elsewhere in order to return the system to service. GR&S has done precisely what the statute contemplates. Accordingly, GR&S is entitled to a proprietary, undivided interest in the utility system owned and operated by Enviracon up to and including the amount of any capital expenditures that it made to repair and replace the collapsed WWTP. Of course, the extent of GR&S's proprietary interest is subject to the Commission's determination that the funds advanced and the expenditures made were reasonable, prudent and subject to verification by the Public Staff. Similarly, IBRC will be entitled to a proprietary interest in the system upon advancement of its share of the reasonable and prudently incurred cost of replacing the failed tank.

7. Transfer of the land without prior written Commission approval

The Public Staff requests the Commission to affirm to IBRC, GR&S, and Enviracon that control of the wastewater treatment plant and rotary effluent distributors, and the land upon which these facilities are located, cannot be changed without prior written Commission approval pursuant to

G.S. 62-111(a). According to the Public Staff, this request arises because of the civil suit in the Carteret County Superior Court, where IBRC seeks a declaratory judgment that IBRC is entitled to terminate the lease for the land upon which the wastewater treatment plant and rotary effluent spray fields are located. The Public Staff and GR&S are concerned that IBRC, if it prevails, would unilaterally terminate the assignment of the leasehold applicable to the land upon which the utility's backbone facilities are located and, presumably, transfer the operations of said facilities to another entity and/or unilaterally discontinue use of the facilities located thereon to provide utility services to GR&S.

G.S. 62-111(a) plainly provides that "no franchise now existing... shall be sold, assigned, pledged, or transferred, nor shall control thereof be changed through stock transfer or otherwise, or any rights thereunder leased... except *after* application to and written approval by the Commission." Thus, the Legislature, by the unambiguous terms of the statute, clearly prohibits the transfer of franchises or leases thereunder before the Commission has had the opportunity to pass upon the merits of the transfer under the public convenience and necessity test.

In the Governor's Club Development rate case, Docket No. W-947, Sub 1, the Commission was faced with a factually analogous situation. In that case, the Commission held that G.S. 62-111(a) required prior written approval before a golf course upon which the wastewater effluent was sprayed pursuant to a negotiated perpetual easement agreement could be transferred from the utility to another entity. The Commission reasoned that, although the statute did not specifically mention golf courses as a covered asset, the statute clearly required prior written approval before significant utility assets could be transferred. The use of the golf course as a utility spray field made the golf course a significant utility asset which could not be transferred without prior Commission approval. Similarly, the leasehold agreement for the land upon which the wastewater treatment plant and the rotary effluent distributors are located is a significant utility asset. Accordingly, neither the land upon which the wastewater treatment plant and the rotary effluent distributors are located nor the lease agreement itself may be transferred without prior written Commission approval.

8. Reconsideration of the 60/40 Allocation

The Commission adopted certain proposals advanced by GR&S and the Public Staff concerning the allocation of capital costs and other expenses incurred by Enviracon which resulted from the collapse of the tank. The Commission thereby determined that IBRC would be responsible for 40% of the capital cost of replacing the failed tank and related expenses and that GR&S would be responsible for 60% of those costs. In response to that conclusion, IBRC requested the Commission to reconsider its conclusion based upon its interpretation of an agreement between GR&S and IBRC.

As has been previously discussed, the Commission has exclusive jurisdiction over the setting of a utility's rates. Ratemaking allows for the allocation and recovery of reasonably incurred costs and expenses among the customers so that a utility that renders adequate service can pay its expenses and be afforded the opportunity to realize a fair return on its investment. The Commission thoroughly reviewed the evidence in this case, including the agreement which purportedly allocates and limits expenses between GR&S and IBRC. The Commission is not bound by the parties' allocation or agreements. After conducting that review, the Commission concluded that the 60/40 split was a fair and reasonable method for allocating the capital costs and expenses which resulted from the unanticipated collapse of the treatment tank between Enviracon's two customers. Nothing that has been said or done since the entry of the Order indicates that the Commission erred in its determination. For that reason, the Commission denies IBRC's petition to reconsider the 60/40 allocation of capital costs and expenses.

II. GR&S's Second Request for Assurances

On April 7, 2006, GR&S filed a motion with the Commission again seeking assurance from Enviracon and IBRC that they would not interfere with the efforts of GR&S and/or its contractors or subcontractors to access the work site to replace and repair the collapsed tank. During oral argument, the parties unanimously affirmed that the tank had been repaired and that it was expected to be operational within a short period of time. All parties concurred that GR&S and its contractors were not interfered with by Enviracon or IBRC in its efforts to repair and replace such plant. It therefore appears to the Commission that there is no longer a controversy for the Commission to decide and that this issue is moot. Accordingly, GR&S's Second Request for Assurances is denied and the matter is dismissed.

III. IBRC's Petition for Reconsideration of the March 7, 2006 Order

On April 6, 2006, IBRC filed Objections to the Order and Petition for the Commission to Reconsider the March 7 Order Conditionally Approving Request. The March 7 Order conditionally approved GR&S's request for assurance that Enviracon and IBRC would not interfere with the efforts of GR&S and/or its contractors or subcontractors to access the work site to replace and repair the collapsed tank. In addition, the Order attached conditions recommended by the Public Staff recognizing that the parties would be entitled to a proprietary interest in the utility to the extent that they provided capital to replace the tank and requiring mediation efforts in the event that the parties could not agree to an allocation of the expense for replacement. IBRC objected to the conditions as going beyond the relief requested by GR&S, contravening the agreement of the parties that there would be no prejudice to the rights and claims of either party, and exceeding the Commission's authority and jurisdiction. To the extent that the April 6 Motion requests that the Commission reconsider GR&S's request for assurance that it would not be interfered with in its efforts to repair and replace the failed tank, for the reasons set forth in Section II of this Order, the matter is moot and is therefore dismissed. To the extent that the motion requests a reconsideration of the Commission's authority to determine whether the parties are entitled to a proprietary interest in the utility system and/or the Commission's jurisdiction to impose the conditions adopted in the March 7, 2006 Order, for the reasons set forth in April 7, 2006 Order and Section I of this Order, IBRC's motion to reconsider is denied.

For the reasons set forth herein:

1. GR&S's Motion to Reconsider is granted in part and denied in part as set forth herein; more specifically,

(a) The Commission denies the motion to reconsider whether the Commission has authority to require IBRC and GR&S to pay a surcharge to reimburse Enviracon for post tank collapse operating expenses;

(b) The Commission rescinds the April 7, 2006 Order to the extent that the Order permitted Enviracon to petition the Commission to abandon its service obligation to GR&S and IBRC for failure of GR&S and IBRC to agree to advance funds necessary to pay post tank collapse operating expenses. The Commission also rescinds the portion of the Order permitting Enviracon to petition to abandon service to GR&S, if GR&S and IBRC fail to agree to advance proportionate shares to replace the failed tank. The Commission reaffirms that portion of the April 7, 2006, Order authorizing discontinuance of service to IBRC for failure to agree to advance its share of the capital cost to replace the failed tank and orders Enviracon to petition the Commission to discontinue service to IBRC in the event that IBRC fails to comply with the conditions set forth above. Finally, the Commission modifies the findings and conclusions in the April 7, 2006 Order in the manner set out in the text of the present Order;

(c) The Commission denies GR&S's motion to reconsider Enviracon's ability to address and rectify conditions which led to the application to make a special assessment;

(d) The Commission denies the motion to consider the liability insurance issues resulting from a lease agreement between GR&S and IBRC in deference to a currently pending proceeding in Carteret County Superior Court addressing these issues; and

(e) GR&S is entitled to a proprietary interest in the utility system to the extent that it has advanced funds necessary to repair and replace the failed WWTP.

2. GR&S's Second Request for Assurances is dismissed as moot.

3. IBRC's Petition to Reconsider the March 7 Order is denied.

4. Except as modified and changed herein, the findings of fact, conclusions of law, and terms and conditions set forth in the Commission's Orders of March 7, 2006 and April 7, 2006 are affirmed.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of August, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Lh082106.01

DOCKET NO. W-176, SUB 32
DOCKET NO. W-176, SUB 30
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 30 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	)	RECOMMENDED ORDER GRANTING PARTIAL RATE INCREASE, CLOSING DOCKET, AND REQUIRING BOND

HEARD IN: Courtroom 1, 2nd Floor, Onslow County Courthouse, E. W. Summersill Building, 109 Old Bridge Street, Jacksonville, North Carolina on Tuesday, August 30, 2005, at 7:00 p.m.

Conference Room, Old County Courthouse, 625 Court Street, Jacksonville, North Carolina on Wednesday, August 31, 2005, at 9:30 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners Robert V. Owens, Jr. and Dr. Robert K. Koger[1].

[1] Dr. Robert K. Koger left the Commission prior to decision-making in this proceeding.

APPEARANCES:

For Scientific Water and Sewerage Corporation:

Robert F. Page, Crisp, Page & Currin, LLP, Attorneys at Law, 1305 Navaho Drive, Suite 302, Raleigh, North Carolina 27609-7444

For the Using and Consuming Public:

Robert S. Gillam and Kendrick C. Fentress, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On May 3, 2005, Scientific Water and Sewerage Corporation (Scientific or Company) filed an application in Docket No. W-176, Sub 32, seeking authority to increase its rates for water and sewer utility service in all of its service areas in Onslow County, North Carolina and requesting authority to implement interim rates.

On June 1, 2005, the Commission issued an Order Establishing General Rate Case and Suspending Rates. On June 9, 2005, the Commission issued an Order Denying Interim Rate Relief, Scheduling Hearing, and Requiring Customer Notice.

On June 14, 2005, Scientific filed a Motion for Amendment of Application in which it requested two additional changes to its miscellaneous tariffs. On June 15, 2005, the Commission issued an Order Amending Customer Notice. On July 1, 2005, Scientific filed a Certificate of Service reflecting that it had given notice as required.

On July 12, 2005, the Public Staff filed a Motion to Consolidate the Sub 32 Docket with previous Dockets Sub 30 and Sub 29, which remain open before the Commission and a Proposed Order Consolidating Dockets.

On July 15, 2005, Scientific filed the direct testimony of its President, Ben Aragona, and George E. Dennis, its accounting consultant.

On July 19, 2005, the Commission issued an Order Consolidating Dockets.

On July 29, 2005, the Public Staff filed the testimony and exhibits of Jerry H. Tweed, Utilities Engineer, and Laura Bradley Stewart, Staff Accountant, and the affidavit of Calvin C. Craig III, Financial Analyst. On August 15, 2005, Scientific filed the rebuttal testimony of Charles Hughes, President of Hughes Consulting, and George Dennis.

Two consumer statements of position were filed in this docket before the evidentiary hearing.

On August 30, 2005, the hearing was held as scheduled and it continued the next day. No customers appeared to testify at the hearing. Scientific presented the direct testimony of Ben Aragona and George Dennis. The Public Staff presented the direct testimony of its witnesses Laura Bradley Stewart and Jerry H. Tweed and introduced into evidence the affidavit of Calvin C. Craig, III. Scientific presented the rebuttal testimony of George Dennis and Charles Hughes.

At the hearing, Public Staff witness Stewart presented updated testimony accepting some of the information provided by Scientific in data request responses provided after the prefiling of her direct testimony. These changes resulted in the Public Staff increasing its recommended rate increase. The Company provided additional information concerning developments that had occurred since its testimony was filed, as well as a revised proposal for salary increases for Ben and Sharon Aragona, and a revised pension plan proposal. The Company requested additional time to obtain an estimate for cleaning of a sewer line right-of-way and to update rate case expense.

The Commission agreed to hold the record open in this case until 14 days before the deadline for filing proposed orders to allow the Company to file additional information and the Public Staff to file revised schedules reflecting witness Stewart's updated testimony. The Public Staff was expressly allowed the right to comment on any additional filings or to cross-examine the Company's witnesses regarding Scientific's supplemental filings. The Public Staff filed its updated Stewart Exhibit I on October 3, 2005. Scientific filed a set of late-filed exhibits on October 6, 2005.

On October 14, 2005, Scientific filed a Motion for Extension of Time to File Proposed Orders and Briefs. On October 18, 2005, the Commission issued an Order Granting Motion for Extension of Time to File Exhibits and Proposed Orders. On November 4, 2005, Scientific filed a second Motion for Extension of Time to File Proposed Orders and Briefs. On November 8, 2005, the Commission issued an Order Granting Second Motion of Time to File Exhibits and Proposed Orders. On November 21, 2005, Scientific filed Dennis Exhibit I, which consisted of accounting schedules. On December 7, 2005, the Public Staff filed a further updated Stewart Exhibit I. On December 9, 2005, the Company filed a revised Dennis Exhibit I.

Based on the foregoing, the evidence adduced at hearing, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT

General Matters

1. Scientific is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. It is a franchised public utility providing water and/or sewer service to customers in this State.

2. Scientific is properly before the Commission, pursuant to Chapter 62 of the General Statutes of North Carolina, for a determination of the justness and reasonableness of its proposed rates for its water and sewer operations.

3. The test period appropriate for use in this proceeding is the twelve months ended December 31, 2003, updated to December 31, 2004.

4. Scientific's present and proposed water and sewer rates are:

	Present	Proposed
Flat Rate Water: Lauradale Water System		
(Water produced from Scientific's wells)		
One bedroom apartments, Lee Garden	$ 9.60 $	$19.20
Two bedroom apartments, Lauradale	$11.20 $	$22.45
Metered Water: Lauradale Water System		
(Water produced from Scientific's wells)		
Base charge per month, zero usage	$ 4.55 $	$11.00
Usage charge, per 1,000 gallons	$ 1.45 $	$ 2.75
Metered Water: Cedar Creek, Raintree, Deerfield, and Summersill Systems		
(Water purchased from Onslow County)		
Base charge per month, zero usage	$ 8.40 $	$13.00
Usage charge, per 1,000 gallons	$ 3.07 $	$ 4.35
Flat Rate Sewer: Residential and Commercial	$20.50 $	$34.58
Metered Rate Commercial Sewer		
Base charge per month, zero usage	$10.00 $	$13.00
Usage charge, per 1,000 gallons	$ 2.00 $	$ 4.34
Deposits:		
For a customer with no previous usage history	$50.00	$100.00

	Present	Proposed
Reconnection Charge: (during normal business hours)		
If water cut off by utility for good cause	$15.00	$50.00
If water discontinued at customer's request	$15.00	$15.00
Reconnection Charge: (after normal business hours, and on Saturday, Sunday and holidays)		
If water cut off by utility for good cause	$30.00	$75.00
If water discontinued at customer's request	$15.00	$35.00

5. At the end of the updated test year ending December 31, 2004, Scientific provided water utility service to 1,587 metered water customers (1,059 purchased water and 528 produced well water) and 1,714 sewer customers (1,700 flat rate residential and 14 metered commercial) in its service areas in Onslow County, North Carolina.

6. Scientific is providing adequate water and sewer service to its customers as evidenced by the limited response to customer notice in this docket; however, there are numerous improvements needed to the water and sewer facilities in order to avoid potential serious service and environmental problems as well as administrative penalties from state regulatory agencies.

7. While Scientific is faced with the need to address serious service and environmental problems, these problems are not, at this time, so urgent or extreme as to justify the inclusion in rate base (or in plant in service) of prospective future plant, or the inclusion in allowable operating expenses of prospective future expense items, even if such ratemaking were allowed by the Public Utilities Act. It is also inappropriate for the Commission to approve, at this time, an innovative ratemaking plan involving a series of stepped-in rate increases.

Rate Base

8. The Company's late-filed exhibits show that it had ordered three telephone auto dialers for use at sewer pump stations and it was currently paying three Sprint telephone bills for the pump stations. It is appropriate to include the cost of these auto dialers, including the initial installation fees, of $1,611 in plant in service.

9. The "new computers/software billing upgrade" and the generators have not been purchased and are not in service, and therefore, are not used and useful; consequently, they cannot lawfully be treated as components of plant in service.

10. The surge tank pump referred to in Scientific's late-filed Exhibit 15 should not be included in plant in service, since a representative three-year average level of pump replacements has been included in maintenance and repair expense.

11. The appropriate level of plant in service for use in this proceeding is $4,222,916, consisting of $556,989 for purchased water operations, $283,495 for produced water operations, and $3,382,432 for sewer operations.

12. The estimated costs of capital improvements listed by Scientific on Schedule 8 of its revised Dennis Exhibit I, filed on December 9, 2005, and not addressed in Findings of Fact Nos. 8-10 above, cannot lawfully be included in rate base since the capital improvements have not been completed and are not used and useful.

13. It is appropriate to exclude purchased water expense from the calculation of cash working capital.

14. It is appropriate to include payroll taxes in the calculation of average tax accruals.

15. The appropriate level of rate base used and useful in providing purchased water utility service is $7,297, consisting of utility plant in service of $556,989 and cash working capital of $13,346, reduced by contributions in aid of construction of $497,307, accumulated depreciation of $62,721, and average tax accruals of $3,010.

16. The appropriate level of rate base used and useful in providing produced water utility service is $10,348, consisting of utility plant in service of $283,495 and cash working capital of

$13,360, reduced by contributions in aid of construction of $253,118, accumulated depreciation of $31,923, and average tax accruals of $1,466.

17. The appropriate level of rate base used and useful in providing sewer utility service is $65,108, consisting of utility plant in service of $3,382,432 and cash working capital of $53,177, reduced by contributions in aid of construction of $3,162,460, accumulated depreciation of $201,363, and average tax accruals of $6,678.

Revenues

18. The appropriate level of end-of-period purchased water service revenues under existing rates is $329,554.

19. The appropriate level of end-of-period produced water service revenues under existing rates is $80,769.

20. The appropriate level of end-of-period sewer service revenues under existing rates is $420,393.

21. The appropriate level of other revenues to include in this proceeding is $17,794, consisting of $5,687 for purchased water operations, $2,893 for produced water operations, and $9,214 for sewer operations.

22. The appropriate level of bad debt expense to deduct from revenues in this proceeding is $8,467, consisting of $2,706 for purchased water operations, $1,377 for produced water operations, and $4,384 for sewer operations.

23. The total level of revenues under present rates is $840,043.

Operation and Maintenance Expenses

24. The appropriate starting point for making a Consumer Price Index based cost of living adjustment to the salaries of Ben and Sharon Aragona is the year ended December 31, 1998, resulting in a cost of living increase of 18.23%. With this adjustment, the appropriate levels of salaries for Ben and Sharon Aragona are $51,928 and $32,731, respectively.

25. It is appropriate to include the salary for a new employee in expenses in this case, since there was no evidence presented that the position was not needed nor was there any disagreement over the general level of salary.

26. The level of salaries for the remaining Scientific employees recommended by the Public Staff, which is based on the current salaries, is appropriate for use in this proceeding.

27. The appropriate level of salaries and wages to include in this rate case is $263,736.

28. It is not appropriate to include in this case an estimated level of pension expense for the employees of Scientific since the pension plan does not now exist and thus is not a known and measurable cost.

29. The lease costs for an excavator and a dump truck proposed by the Company are estimated expenses that have not been incurred; therefore, these costs are not known and measurable and should not be included in expenses in this case.

30. It is not appropriate to include in expenses additional estimated costs for contract lawn mowing service without making an offsetting adjustment to salaries and wages. Furthermore, there is no executed agreement for such services.

31. It is inappropriate to include $100,000 in maintenance and repairs for backflow preventers, since the backflow preventers have not yet been installed, and they do not constitute a known and measurable change to test year expenses.

32. The three-year average for pump replacements recommended by Public Staff witness Tweed is representative of the ongoing level and is appropriate for use in this proceeding.

33. The Company has not provided sufficient documentation regarding a sewer jet lease and sewer line cleaning to support any pro forma adjustments in this case.

34. It is not appropriate to include in this case an estimated amount for sewer right-of-way clearing since this is a future expense whose amount is not known and measurable.

35. The appropriate level of maintenance and repairs to include in this rate case is $36,698.

36. It is not appropriate to include in this case the $15,000 estimated pro forma cost of professional services related to contracts for Charles Hughes and George Dennis, since this is a future expense whose amount is not known and measurable.

37. The appropriate level of rent expense to include in this proceeding is $11,699.

38. The Company's proposed cost to lease two new pickup trucks is not known and measurable and should not be included in expenses in this case.

39. The appropriate level of operation and maintenance expenses for use in this proceeding is $842,274, consisting of $309,975 for purchased water operations, $106,883 for produced water operations, and $425,416 for sewer operations.

Depreciation and Taxes

40. The appropriate level of depreciation expense for use in this proceeding is $16,584.

41. The appropriate level of property taxes to include in this proceeding is $974.

42. The appropriate level of payroll taxes for use in this proceeding is $21,896.

43. Based on the other findings and conclusions set forth in this order, the appropriate level of regulatory fees under present rates for use in this proceeding is $1,008.

44. Based on other findings and conclusions set forth in this order, the appropriate level of gross receipts taxes under present rates for use in this proceeding is $42,105.

45. It is appropriate to calculate state and federal income taxes based on the consolidated taxable income for purchased water, produced water, and sewer operations.

Rate of Return

46. The operating ratio method, which allows a margin on operating revenue deductions requiring a return, is the proper method for determining Scientific's revenue requirement.

47. A margin of 8.5% on operating revenue deductions requiring a return is just and reasonable for Scientific.

Rates, Fees and Other Matters

48. The total annual revenues necessary to allow Scientific the opportunity to earn the 8.5% margin found just and reasonable are $370,706 for purchased water operations, $131,984 for produced water operations, and $535,363 for sewer operations.

49. The rates approved herein will allow Scientific the opportunity to earn the 8.5% margin found reasonable.

50. Scientific has not provided cost justification for proposed changes in its reconnection fees.

51. The amount of customer deposits should be determined by Scientific in compliance with the Commission's Rule R12-4(a), and there is no need to specify a deposit amount on the tariff sheet for Scientific.

52. The currently charged $2.00 credit card convenience fee should be included on Scientific's tariff sheet.

Consolidated Dockets

53. Docket No. W-176, Sub 30, which involves Scientific's last general rate case and has been consolidated with this case for disposition, can appropriately be closed.

54. In Docket No. W-176, Sub 29, which involves a notification of contiguous extension of sewer service by Scientific into Maynard Manor Subdivision and has been consolidated with this case for disposition, Scientific should be required to post a bond in the amount of $130,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 3

The evidence supporting these findings of fact is contained in the application and in the Commission's records. These findings are primarily jurisdictional and informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 AND 5

The evidence supporting these findings of fact is contained in the application and in the testimony of Public Staff witness Tweed and is not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

One e-mail and one letter complaint regarding rates and service appear in the Commission's official file in this docket. Both object to the proposed rate increase; one mentions a previous leak in the water system, and the other objects to the water quality. Company witness Aragona testified that the complained-of leak had been repaired with some degree of difficulty; that he had not received a complaint from the customer who wrote the Commission regarding water quality; and that he had received no bad water samples. No customers testified at the public hearing.

Public Staff witness Tweed testified that his inquiries at the Division of Environmental Health (DEH) and the Division of Water Quality (DWQ) of the Department of Environment and Natural Resources (DENR) revealed that the water systems are in compliance with testing and water quality standards required by the Safe Drinking Water Act, and that there have been a few minor exceedances of the wastewater treatment plant (WWTP) discharge permit limits.

Witness Tweed testified that there is a pending administrative penalty before DEH involving noncompliance with rules requiring elevated storage for water systems with more than 299 service connections. DEH has stayed the enforcement action pending resolution of two solutions offered by Scientific: (1) connection to the City of Jacksonville or (2) development of a high-yield well. A high yield well has been drilled but not placed into service by Scientific.

Witness Tweed further testified regarding a DWQ recommended enforcement action concerning numerous needed improvements to the WWTP and wastewater collection system.

Company witness Aragona testified that the systems are old, with major components needing to be rebuilt or replaced, and that Scientific had been unable to raise the money to fund the needed repairs and improvements.

Witness Tweed recommended that Scientific be required to file a report within 60 days of the Commission's order in this case, addressing the specific steps to be taken regarding the following needed improvements to the water and sewer systems, with the detailed cost and estimated timeframe for completion of each step:

WATER SYSTEM

Place 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.

SEWER SYSTEM

(1) Construction and rehabilitation of the existing and new sludge holding facilities, including the ability to thicken the sludge.
(2) Removal of accumulated sludge from the polishing ponds and drying bed area.
(3) Providing DWQ approved, operable alarm systems at the wastewater treatment plant and all pump stations.
(4) Rebuilding the facilities at the Deerfield pump station.
(5) Installing a generator at the Maynard Manor pump station.
(6) Repair or replacement of the influent bar screen at the wastewater treatment plant.
(7) Repair of clogged or blown air diffusers at the wastewater treatment plant.
(8) Installation of a fence around the sludge drying facilities, unless the facilities are slated for abandonment.

The Commission concludes that Scientific should be required to file the recommended report within 60 days of the date of this order, and that the report should reflect serious and careful consideration and a clear intention to move forward. Furthermore, a progress report should be filed by Scientific six months after the Commission's order showing the status of the projects including obtained funding and the timeframe for completion of the above listed improvements.

The Public Staff is requested to monitor the status and make the appropriate recommendation to the Commission regarding any need for appointment of an emergency operator. G.S. 62-118 defines an emergency as "the imminent danger of loss of adequate water or sewer utility service, or actual loss thereof." One could argue that an emergency already exists, due to the inadequacy of the facilities and the inability of Scientific to obtain funding to upgrade the facilities; but, since the system is functioning reasonably well at present, and no customers appeared at the hearing to complain about the quality of their service, the Commission declines to find an emergency at this time. Obviously, however, if real progress is not made by Scientific, the problems with the Company's system will become increasingly severe, with the very real possibility that an emergency operator may be required.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the application and the testimony and exhibits of Company witnesses Aragona, Dennis and Hughes and Public Staff witnesses Stewart and Tweed.

All of Scientific's witnesses contended emphatically that this proceeding should not be treated as a typical general rate case. They asserted that Scientific is faced with very serious problems that could result in a disastrous collapse of its system, and that the Commission's traditional method of evaluating rate increase proposals will not generate enough revenue for Scientific to correct the weaknesses in its system. Witness Aragona testified: "Scientific simply does not have a record of financial performance sufficient to allow it to borrow sums from a bank or other lending institution to fund the capital improvements which need to be made to the various operating systems, both water and sewer." Witness Dennis stated that because of its weak financial condition, Scientific is unable to incur new expenses, such as the adoption of a pension plan for its employees, without assurance from the Commission that the expenses will be recovered through rates. Similarly, witness Hughes testified "that this case is anything but normal. That we should not just look at the lowest rates that can be charged as our goal, but our goal should be to look deeper into all of the issues so that we can make sure that we have a viable water company."

In order to provide sufficient funds to correct the problems in its system, Scientific proposed a pro forma adjustment to its rate base to include the estimated costs of new equipment and system repairs to be performed in the future. In Schedule 8 of its application the Company listed a number of capital improvements with an estimated total cost of $1,309,700. Witness Dennis testified that these improvements would enable Scientific to eliminate the most serious existing difficulties with its system, and that their costs should be added to rate base. Similarly, in Schedule 9 of the application, the Company listed a series of annual operating expenditures it hopes to make in the future to enable its system to function more efficiently. The estimated total of these expenditures is $246,905, and witness Dennis recommended that they be added to actual test period expenses as a pro forma adjustment.

As an alternative to including the $1,309,700 in proposed capital improvements in rate base immediately, witness Hughes proposed that the Commission consider an innovative ratemaking plan. Under this plan, Scientific would obtain a construction loan from a bank, with the Company becoming eligible for draws on the loan as particular projects were completed. The Commission would approve a series of stepped-in rate increases, with increases being put into effect as draws were made on the loan, so as to enable the Company to cover its interest payments. Witness Hughes further testified that if Scientific is not given the relief it needs in this case, at some future time it may be necessary to appoint an emergency operator and have the emergency operator assess the customers for the costs of the needed system improvements – something that would not, in his opinion, be in the best interests of either the Company or the customers.

The Public Staff's witnesses opposed the inclusion of future capital improvements in rate base and future expense items in allowable operating expenses. Witness Stewart testified that she had removed these proposed adjustments in calculating her recommended revenue requirement. Similarly, witness Tweed testified that plant improvements that have not yet been completed are not used and useful, and therefore they cannot be included in the calculation of rates. He further stated that although most of the capital improvements listed in Schedule 8 to the application need to be implemented, not all of them are necessary or required. Witness Tweed presented a listing of the improvements that are most pressing and critical. He acknowledged that Scientific does not currently have the funds to carry out the improvement projects he viewed as most critical. When asked how Scientific should raise the money to carry out these projects, he recommended that the Company consider obtaining funds from a lender, from its owners or other investors, or through an innovative ratemaking plan, and he also noted that Scientific is looking into a potential sale of its system. With regard to the innovative ratemaking plan put forward by the Company in this case, witness Tweed testified that at present the plan is not sufficiently concrete to be adopted, and considerable time will be necessary for the Company to flesh it out and provide the necessary details.

On cross-examination, Company witnesses Dennis and Hughes testified that Scientific had met with the Public Staff in July 2005 to discuss its proposal for an innovative ratemaking plan based on a bank loan agreement and a series of stepped-in rate increases. The Public Staff responded to Scientific's proposal in a letter of July 25 to Scientific's counsel. In this letter, which was admitted in evidence as Public Staff Dennis Cross-Examination Exhibit 4, the Public Staff expressed interest in the innovative ratemaking plan and encouraged Scientific to continue working on it. The letter stated that in order to receive the Public Staff's endorsement, an innovative ratemaking plan would need to comply with certain principles. The most important of these principles reflected the Public Staff's concern that the plan should comply with the requirements of the Public Utilities Act. The Public Staff stated that "a stepped-in increase should not be implemented until the individual project(s) associated with it have been completed and placed in service," and "a stepped-in rate increase should be no greater than the increase that would have resulted from the completion of the project(s) in a general rate case." In other words, the stepped-in rate increases should not be designed automatically to match the interest payments due from Scientific to the bank under the loan agreement, but instead would need to be driven by standard utility ratemaking factors such as depreciation, return and taxes.

Witness Hughes testified on cross-examination that the Public Staff offered to meet with Scientific again and discuss the innovative ratemaking plan further. However, Scientific was under no obligation to obtain the Public Staff's approval for its proposal; and instead of continuing to discuss the matter with the Public Staff, the Company chose to present the issue to the Commission, which is the ultimate decision-making authority on all regulatory matters.

In its late-filed exhibits filed on October 6, 2005, Scientific submitted documentation relating to some of the items listed in Schedule 8 to its application, contending that these specific items were in fact used and useful. In its accounting schedules filed on November 21, 2005, Scientific revised its estimate of future capital improvements on Schedule 8 to $686,818. Scientific also eliminated Schedule 9, the list of anticipated future expenditures, and transferred the expenses listed therein to its schedules of adjusted test year expenses.

Essentially Scientific has requested that the Commission depart from ordinary ratemaking procedure in three respects: (1) by including in rate base the future plant improvements listed in Schedule 8 to the application; (2) by including in allowable operating expenses the future expense items originally listed in Schedule 9; and (3) by adopting an innovative ratemaking plan, in the event the Commission chooses not to include the Schedule 8 plant improvements in rate base. The Commission has given careful consideration to each of these proposals and concludes that none of them may lawfully be allowed.

With respect to Scientific's first request, the proposed capital improvements listed in Schedule 8 may not be included in rate base (or in the plant in service account). G.S. 62-133(b)(1) clearly specifies that the rate base is to include only "the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period." Construction of the capital improvements in Schedule 8 has not been completed, and the great majority have not even been started; thus it is clear that they are not used and useful. The Commission cannot lawfully include them in rate base.

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.[1] When customers are asked to contribute capital to the utility – whether by assessing them directly for construction costs,

[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.

or by including in rate base capital costs that have not in fact been incurred – the roles of the customer and investor are distorted.

There is one situation in which the utility's customers may be assessed for capital costs. 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. Moreover, when an assessment is made, pursuant to G.S. 62-118(c), the customers "retain a proprietary interest in the system to the extent of the capital so advanced" and thus take on the role of investors.

All the witnesses at the hearing were in agreement that although Scientific's system has serious problems, there is no emergency at this time, and the appointment of an emergency operator is not necessary. For the time being, the system is functioning reasonably well. Absent the necessity of appointing an emergency operator, the Commission concludes that there is no legal basis for requiring customers to pay for proposed capital improvements that have not been built and may never be built. Consequently, an order including in rate base property that is not used and useful would be unlawful.

With respect to the capital improvements listed in Schedule 8 that are the subject of late-filed exhibits and are asserted to be used and useful, the Commission will address these in the discussion of Findings of Fact Nos. 8-17 below.

The Commission is likewise unable to agree with Scientific that the proposed future expenses originally listed in Schedule 9 to the application should be treated as allowable operating expenses. Clearly, allowable operating expenses must be based on the expenses incurred during a historical test period, not a future test period. G.S. 62-133(c) provides in relevant part:

> The test period shall consist of 12 months' historical operating experience prior to the date the rates are proposed to become effective, but the Commission shall consider such relevant, material and competent evidence as may be offered by any party to the proceeding tending to show actual changes in costs . . . within a reasonable time after the test period . . . based upon circumstances and events occurring up to the time the hearing is closed.

G.S. 62-133(c) does not allow the Commission, as a matter of discretion, to make pro forma adjustments treating planned future expenses as if they had been incurred in the test period. The expenses must be incurred within the test period or within a reasonable time thereafter, and in determining whether a particular expense was incurred "within a reasonable time after the test period," the criterion traditionally used by the Commission is whether it was known and measurable as of the close of the hearing.

Accordingly, the Commission cannot lawfully include planned future expenses in rates as operating expenses. Where Scientific has offered evidence suggesting that particular expenses originally listed in Schedule 9 are allowable as test year expenses, or as known and measurable changes to test year expenses, these expenses will be addressed in the discussion of Findings of Fact Nos. 24-39 below.

Finally, the Commission concludes that it is not appropriate at this time to adopt an innovative ratemaking plan of the type proposed by witness Hughes, involving a series of stepped-in rate increases tied to a construction loan for plant improvements. The Commission emphasizes that it is not flatly opposed to innovative ratemaking plans. On the contrary, the Commission is willing to consider any such a plan if it complies with G.S. 62-133 and the related ratemaking statutes and is determined to be in the best interests of the Company and the ratepayers.

The primary problem with the innovative ratemaking plan proposed by witness Hughes in this case is that it is not sufficiently specific and definite to be reviewed and evaluated by the Commission. A ratemaking plan that involves a series of stepped-in rate increases should specify the date when each increase will 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 should provide clear and unambiguous criteria for determining when increases will be effective and how the amount of an increase will be determined. If the plan is tied to a loan agreement, the provisions of the agreement must be available for the Commission's review. The plan presented by Company witness Hughes does not have this degree of specificity. For example, it clearly contemplates a construction loan to Scientific from a bank or other lender, but no loan agreement has been negotiated. The plan contains no information on the amount and timing of the stepped-in rate increases to be implemented.

At a minimum, the Commission must have all of this information in order to make an informed legal and economic analysis of the plan and determine whether it is in the public interest. The Commission must therefore reject the proposed innovative ratemaking plan, as presented, without prejudice to the right of Scientific to propose a new plan in a future proceeding.

The Commission does not believe that its refusal to adopt the proposed innovations proposed by witness Hughes' proposed innovative ratemaking plan, together with its rejection of Scientific's proposal to include prospective future plant in rate base, will leave the Company without any means of raising the capital needed to improve its system. The rate increase approved in this order will provide Scientific with a significant amount of new income that can be invested in equipment or plant repairs. Obviously this additional income is not sufficient to pay for all the needed plant improvements, but it should not be expected that the cash flow from any company will fund all its needed capital expenditures. The additional income should, however, significantly improve Scientific's ability to attract capital.

Testimony at the hearing indicated that Scientific is actively seeking a bank loan, and the rate increase granted in this case may assist the Company in qualifying for a loan. The Company may also wish to consider an infusion of equity capital; typically, large corporate construction projects are funded through a combination of debt and equity investment. If, as was indicated at the hearing, Scientific's owners are not currently in a position to make any additional investment in the Company, they may choose to approach outside investors, with a view to obtaining equity capital in exchange for a stock interest in the Company. Finally, if all other methods of raising funds prove unsuccessful and the Company finds itself unable to make the needed repairs to its system, its management has the option of selling the system to new owners with greater financial resources.

The Commission further notes that Scientific also has the option of the filing another rate case application once it has made the necessary plant improvements and incurred the additional operating expenses discussed in this case. The Company could request expedited review of its application filed under traditional ratemaking rules and procedures. Such a filing in close succession to the instant rate case would sharply reduce the amount of time and expense associated with the new rate case application.

For all these reasons, the Commission concludes that Scientific should not be permitted to include the costs of prospective future plant in rate base; that prospective future expenses should not be treated as allowable operating expenses; and that Scientific's proposed innovative ratemaking plan should not be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 – 17

The evidence supporting these findings is contained in the application and the testimony of Public Staff witnesses Stewart and Tweed and Company witnesses Dennis and Aragona and the entire record in this docket. The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of rate base to be used in this proceeding.

Item	Company	Public Staff	Difference
Plant in service	$4,221,305	$ 4,222,916	$ 1,611
Plant additions	686,818	0	(686,818)
Accumulated depreciation	(344,645)	(296,007)	48,638
Contributions in aid of construction	(3,912,885)	(3,912,885)	0
Cash working capital	142,852	75,508	(67,344)
Average tax accruals	(7,505)	(10,679)	(3,174)
Original cost rate base	$ 785,940	$ 78,853	$ (707,087)

As shown in the preceding table, the Public Staff and the Company agree on the level of contributions in aid of construction. Therefore, the Commission concludes that the level agreed to by the parties for contributions in aid of construction is appropriate for use in this proceeding.

PLANT IN SERVICE

The parties differ on whether it is appropriate to include in plant in service costs related to the auto dialers, new computers/software billing upgrade, generators, and a surge tank pump based on the Company's late filed exhibits. In its revised schedules filed on December 7, 2005, the Public Staff included $1,611 related to the auto dialers in plant in service, while the Company included the same amount under plant additions, so that the only difference between the parties concerning the auto dialers is whether the cost should be included under plant in service, or under the estimated plant additions. The Commission concludes that it is appropriate to include the auto dialer costs in plant in service, since these costs are known and measurable.

The parties disagree on whether the new computers/software billing upgrade and generator costs included in the Company's late-filed exhibits should be included in rate base in this proceeding. The Company's late-filed Exhibit 8 consisted of two quotations from Carolina Meter & Supply, one for the purchase of an "Itron AMR – Water Pit ERT System" for $6,565.21, and the other for the purchase of a four-inch "Turbo Series Meter" at a price of $979.05. These items were described as "new computers/software billing upgrade" in Dennis Exhibit I, although it is not clear that this is an accurate label for the equipment described in Exhibit 8.

Scientific also submitted, as its late-filed Exhibits 9 and 11, quotations from Gregory Poole Power Systems for the purchase of two diesel generators at the prices of $19,020 and $23,175, respectively. The cover letter for the late-filed exhibits stated that DENR had been urging Scientific to buy the generators, and that Scientific may possibly have the opportunity to lease these generators instead of purchasing them.

All three of these late-filed exhibits are merely quotations rather than executed contracts. These plant items have not been purchased, are not in service, and therefore, are not known and measurable. Both the new computers/software billing upgrade and the generators fall into the category of future capital improvements, and as previously discussed, they cannot lawfully be treated as components of plant in service.

Finally, the parties disagree on whether $9,468 for the cost of a surge tank pump should be included in rate base. As discussed under maintenance and repairs expense, a representative level of pump replacements has been included in maintenance and repairs; therefore, it would be inappropriate to also include the surge tank pump in plant in service.

Based on the foregoing, the Commission concludes that the appropriate level of plant in service for use in this proceeding is $4,222,916, consisting of $556,989 for purchased water operations, $283,495 for produced water operations, and $3,382,432 for sewer operations.

PLANT ADDITIONS

Scientific included estimated capital improvements of $1,309,700 as plant additions on Schedule 8 of its application. In its revised Dennis Exhibit I filed on December 9, 2005, Scientific reduced its estimated amount of plant additions to $686,818.

Elsewhere in this order, the Commission has concluded that the estimated capital improvements listed by Scientific cannot lawfully be included in rate base, since the capital improvements have not been completed and are not used and useful. As previously discussed under plant in service, the Company did provide sufficient documentation for the auto dialers, and the actual costs related to this capital improvement has been included in plant in service.

ACCUMULATED DEPRECIATION

The difference between Scientific and the Public Staff regarding accumulated depreciation results from the parties' disagreement over the levels of plant in service, plant additions, and contributions in aid of construction. Based on the conclusions concerning plant in service, plant additions, and contributions in aid of construction reached elsewhere in this order, the Commission concludes that the amount of accumulated depreciation presented by the Public Staff is reasonable and appropriate for use in this proceeding.

CASH WORKING CAPITAL

The difference between the level of cash working capital recommended by the parties is due to (1) a difference on whether purchased water should be deducted from operation and maintenance expense in calculating cash working capital, and (2) the parties having recommended different levels of expenses. In its calculation of cash working capital, the Public Staff excluded purchased water expense. The Company did not dispute the Public Staff's methodology in its rebuttal testimony or at the hearing, but in its revised Dennis Exhibit I, the Company included purchased water expense in its calculation. The Commission concludes that it is appropriate to exclude purchased water expense from the calculation of cash working capital. This treatment is consistent with Commission practice in other cases, and recognizes the fact that there is no lag between the time a Company collects revenues from its customers for the provision of water purchased from others and the time the Company pays for the purchased water, since purchased water expense is not due until after the service is provided, the meter has been read, and the Company has been billed by its supplier for the service. Based upon conclusions regarding the appropriate levels of expenses reached elsewhere in this order and the exclusion of purchased water from the calculation, the Commission concludes that the appropriate level of cash working capital is $79,883, consisting of $13,346 for purchased water operations, $13,360 for produced water operations, and $53,177 for sewer operations.

AVERAGE TAX ACCRUALS

The difference in the level of average tax accruals recommended by the parties is due to the exclusion of payroll taxes from the calculation by the Company. The Public Staff calculated average tax accruals as one-half of property taxes and one-sixth of payroll and gross receipts taxes. The Company did not dispute the Public Staff's methodology in its rebuttal testimony or at the hearing. However, in its revised Dennis Exhibit I, the Company did not include one-sixth of payroll taxes in its calculation of average tax accruals. The Commission concludes that it is appropriate to include payroll taxes in the calculation of average tax accruals. This methodology is consistent with Commission practice in other cases, and reflects the fact that payroll taxes are due quarterly. As a result, the Company collects payroll taxes through rates during the quarter, but does not have to pay the taxes to the appropriate governmental agency until after the end of the quarter. In order to reflect that the Company has the use of this money until it has been paid to the governmental agency, the average tax accruals for payroll taxes should be deducted from rate base. Therefore, based upon conclusions reached elsewhere in this order concerning the appropriate levels of property taxes, payroll taxes, and gross receipts tax, the Commission concludes that the appropriate level of average tax accruals to be deducted from rate base in this proceeding is $11,154, consisting of $3,010 for purchased water operations, $1,466 for produced water operations, and $6,678 for sewer operations.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of original cost rate base for use in this proceeding is $82,753, consisting of $7,297 for purchased water operations, $10,348 for produced water operations, and $65,108 for sewer operations, as shown below:

Item	Purchased Water	Produced Water	Sewer
Plant in service	$ 556,989	$ 283,495	$ 3,382,432
Plant additions	0	0	0
Accumulated depreciation	(62,721)	(31,923)	(201,363)
Contributions in aid of construction	(497,307)	(253,118)	(3,162,460)
Cash working capital	13,346	13,360	53,177
Average tax accruals	(3,010)	(1,466)	(6,678)
Original cost rate base	$ 7,297	$ 10,348	$ 65,108

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18 - 23

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Stewart and Tweed and the application filed in this docket. The Company did not contest the levels of service revenues, late payment fees, miscellaneous revenues, and uncollectibles recommended by the Public Staff. Therefore, the Commission concludes that the levels of service revenues, late payment fees, miscellaneous revenues, and uncollectibles recommended by the Public Staff are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24 – 39

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Stewart and Tweed, Company witnesses Aragona, Dennis and Hughes, the application and the entire record in this proceeding.

The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of operation and maintenance expenses to be used in this proceeding:

Item	Company	Public Staff	Difference
Administrative and office	$ 25,028	$ 25,028	$ 0
Chemicals	6,532	6,532	0
Electric power	53,070	53,070	0
Employee benefits	84,425	53,057	(31,368)
Insurance	11,499	11,499	0
Maintenance and repairs	230,462	36,698	(193,764)
Other expenses	9,772	9,772	0
Penalties	16	16	0
Permit fees and licenses	2,335	2,335	0
Professional fees	25,538	10,538	(15,000)
Purchased water	203,211	203,211	0
Rate case expense	14,137	14,137	0
Rent	15,600	11,699	(3,901)
Salaries and wages	311,120	228,736	(82,384)
Sludge removal	96,771	96,771	0
Telephone and communication	9,730	9,730	0

Testing	23,939	23,939	0
Transportation	19,534	10,406	(9,128)
Travel expenses	100	100	0
Total operation & maintenance expense	$1,142,819	$ 807,274	$(335,545)

As shown in the preceding table, the Public Staff and the Company agree on the levels of administrative and office expense, chemicals, electric power, insurance, other expenses, penalties, permit fees and licenses, purchased water, rate case expense, sludge removal, telephone and communication, testing, and travel expenses. Therefore, the Commission finds and concludes that the levels agreed to by the parties for these items are appropriate for use in this proceeding.

SALARIES AND WAGES

The parties disagree on (1) the salary increases for Ben and Sharon Aragona, (2) the inclusion of the salary for a new employee, and (3) an unreconciled difference in salaries for the remaining employees.

Salary Increases

The parties disagree on the level of salaries for Ben and Sharon Aragona, who are also shareholders of Scientific. In its application, Scientific included pro forma increases in salaries of $41,026 for Ben Aragona and $18,658 for Sharon Aragona, resulting in a total proposed salary of $79,205 for Ben Aragona and $50,000 for Sharon Aragona. The Public Staff requested justification for Scientific's pro forma salary increases but no justification was provided prior to the hearing. In her prefiled testimony, Public Staff witness Stewart included salaries for Ben and Sharon Aragona at their current salary levels which were $43,680 for Ben Aragona and $31,200 for Sharon Aragona. Witness Stewart further testified that she did not include Scientific's pro forma salary increases for Ben and Sharon Aragona since Scientific had not provided any justification for the increases. According to witness Stewart, these increases, which equated to an overall increase in their salaries of over 80%, were unreasonable and therefore should not be allowed.

In his prefiled rebuttal testimony, Company witness Dennis did not address salaries. At the hearing, however, Company witness Dennis decreased his pro forma level of salaries to $60,000 for Ben Aragona and $40,000 for Sharon Aragona. Witness Dennis testified that he had applied a cost of living index to the Aragonas' salaries, using their W-2 forms for the year ending December 1999 as his beginning point. He then calculated the percentage increase in the Consumer Price Index (CPI) for Urban Wage Earners and Clerical Workers from January 1999 to the present, and he applied this percentage increase to their 1999 salaries, resulting in salaries of $54,517 for Ben Aragona and $35,160 for Sharon Aragona. Witness Dennis then rounded the salaries up to $60,000 for Ben Aragona and $40,000 for Sharon Aragona. He testified that given the level of responsibilities and duties of these employees, he felt that these salary levels were appropriate.

Scientific stated in its proposed order that the salary levels presented at the hearing for Ben Aragona and Sharon Aragona were the minimum acceptable salary levels. In revised Dennis Exhibit I, filed on December 9, 2005, Scientific included salaries of $80,000 for Ben Aragona and $50,000 for Sharon Aragona. The Company stated in its proposed order that the salary levels, for Ben Aragona and Sharon Aragona, included in revised Dennis Exhibit I, were necessary based on the size of the utility, and the need for the utility to be able to attract the capital and to borrow the funds necessary to make further improvements to the system.

In its final exhibits filed on October 3, 2005, the Public Staff included salaries of $51,928 for Ben Aragona and $32,731 for Sharon Aragona.

For purposes of this proceeding, the Commission accepts the methodology used by Company witness Dennis to adjust salaries for the increase in cost of living. However, witness Dennis erred when he calculated a factor based on the increase in the CPI from January 1999 to the present and applied this factor to the salaries for the full calendar year 1999. By doing so, witness Dennis in effect gave the Aragonas a salary increase for 1999 on top of the salary increases already reflected in the 1999 salaries. This is a significant error; although witness Dennis testified that the 1999 salaries for Ben and Sharon Aragona were only "slightly" higher than the prior year, the actual increases in Ben and Sharon Aragona's salaries in 1999 were 6% and 8.5%, respectively.

The Commission concludes that the appropriate starting point in adjusting salaries for cost of living increases is the year ended December 31, 1998, since that is the test year of Scientific's last general rate case. Furthermore, according to witness Dennis, 1998 was the first full year that the Aragonas' salaries were in place. Since the appropriate starting point for calculating the cost of living increase is the year ended December 31, 1998, the percentage increase should be calculated beginning with the annual index for 1998, which reflects the average prices for that year. When the July 2005 index of 185.5 is divided by the 1998 annual index of 156.9, the resulting cost of living increase to be applied to the 1998 salaries is 18.23%. Based on this cost of living increase, the Commission concludes that the appropriate levels of salaries for Ben and Sharon Aragona are $51,928 and $32,731, respectively.

The Commission finds that the Company did not provide any supporting data or comparisons to other water and wastewater utilities, similar in size to Scientific, to justify its recommended salaries of $80,000 for Ben Aragona and $50,000 for Sharon Aragona included in its final accounting schedules submitted to the Commission. Additionally, the Commission does not agree with Company witness Dennis' minimum salary level proposal, in which his calculated salaries are rounded up to $60,000 for Ben Aragona and $40,000 for Sharon Aragona. Witness Dennis did not provide any detailed justification for rounding up the salaries, and particularly not for rounding them up to the next highest ten thousand dollars, rather than the next highest thousand dollars or hundred dollars.

<u>New Employee</u>

The parties disagree on whether the salary for a new employee should be included in salaries and wages expense in this case. Public Staff witness Stewart testified that this new position should not be included since the Company did not provide any documentation to support the actual annual salary level of the employee or the actual hire date. Company witness Aragona testified during the hearing that the Company had hired a new employee starting at $35,000 that has good qualifications for maintenance and repair needed for a water and sewer utility. Although the Company included an annual salary of $36,000 related to the new employee, in its final accounting schedules provided to the Commission, witness Dennis testified at the hearing that the new employee's salary is $35,000, not $36,000.

The Commission concludes that it is appropriate to include the new employee, at an annual salary of $35,000, in this case. There was no evidence presented that this position was not needed nor was there any disagreement over the general level of compensation.

Unreconciled Difference

In her prefiled testimony, Public Staff witness Stewart testified that, based on her review of the books and records and discussions with Company personnel, she adjusted salaries and wages to reflect the current salaries. Company witness Dennis did not address salaries and wages in his prefiled testimony. At the hearing, witness Dennis provided testimony concerning the appropriate level of salaries for Ben and Sharon Aragona, and the salary for the new employee, but did not discuss the salaries for the remaining employees. In the Company's revised Dennis Exhibit I, the salaries for the employees, other than Ben and Sharon Aragona and the new employee, are $1,043 greater than the amounts recommended by the Public Staff. The Commission concludes that the Company has not provided sufficient evidence concerning the $1,043 difference in salaries, and finds that the levels of salaries for the remaining employees recommended by the Public Staff are appropriate for use in this proceeding.

Summary

Based on the foregoing, the appropriate level of salaries for use in this proceeding is $263,736, consisting of $57,548 for purchased water operations, $50,078 for produced water operations, and $156,110 for sewer operations.

EMPLOYEE BENEFITS

The parties disagree on the amount, if any, to be included in this case for a pension plan proposed by Scientific. Scientific included in its application a pro forma adjustment of $31,467 for the pension plan. The record reveals that shortly before the hearing, the Company provided the Public Staff with a document entitled "Scientific Water & Sewerage Corporation – Profit Sharing Plan and Trust – Summary Plan Description."

Public Staff witness Stewart testified that she objected to the plan based on the lack of legal documents for the plan and the excessive amount requested. As outlined in the "Summary Plan Description," the pension plan is a 401(k) plan with a mandatory Company contribution equal to 10% of each employee's salary, with no matching funds provided by the employees.

Company witness Dennis testified that in the week since the "Summary Plan Description" had been provided to the Public Staff, the Company had changed the plan, and it now provided for a mandatory contribution of 6% of each employee's salary, plus additional contributions of up to 4% to match an employee's voluntary contributions. He further testified that the total cost of the amended plan would be $31,368, including annual plan contributions of $28,112, annual administrative costs of $2,823, and one-time installation costs of $1,300, amortized over three years at $433 per year. The $28,112 in contributions is based on an assumption that each employee will contribute enough to qualify for the full 4% match.

Witness Dennis accepted, subject to check, the accuracy of Public Staff Dennis Cross-Examination Exhibit 3. This exhibit reviews the pension plans of other water and sewer utilities in

North Carolina and one gas utility, showing that each company's contribution to its pension plan is well below the level proposed by Scientific. The average company contributions are 3.75% for Aqua North Carolina, Inc., 2% for Hydraulics, Inc. (before it was sold by Manuel Perkins to Aqua), 2.86% for Piedmont Natural Gas Company, Inc., and 7% for Utilities, Inc. Except for Utilities, Inc., all the company contributions are based on matching an employee's contributions; only Utilities, Inc. makes mandatory contributions without regard to the employee's participation.

Witness Dennis testified on cross-examination that the "Summary Plan Description" is only a working model; it is not the formal plan document that creates rights and obligations affecting the Company and its employees, and Scientific has made no definite decision to execute a formal plan document. He further testified that in order for the plan to take effect, Scientific will have to develop a formal plan document; it will have to enter into a written agreement with a fiduciary who will serve as trustee; and it will have to obtain approval of the plan from the Internal Revenue Service. Witness Dennis acknowledged that the "Summary Plan Description" allows Scientific to amend or terminate the plan at any time once it has been adopted.

Witness Dennis further testified that a pension plan is an important aspect in attracting and retaining competent employees and that the Commission should approve the proposed plan and require the Company to file with the Commission, within 90 days, the official documents showing the compliance of the Company with its pension plan proposal.

After reviewing the testimony and exhibits relating to the proposed pension plan, the Commission concludes that it cannot be considered an allowable operating expense. No expenses for the pension plan were incurred during the test year, and none had been incurred as of the close of the hearing. It is certainly possible that, in order to attract and retain competent employees, at some future time the Company may implement a pension plan, but at present there are so many uncertainties and unknowns surrounding the plan that its ultimate costs can, at best, only be considered speculative. An operating expense must be known and measurable as of the close of the hearing in order to be allowable, and at present, Scientific's proposed pension plan does not meet that standard.

MAINTENANCE AND REPAIRS

The parties disagree on the following maintenance and repair items: (1) lease payments for an excavator and a dump truck, (2) lawn mowing service, (3) backflow preventers, (4) pump rebuilding costs, (5) a sewer jet lease, and (6) right-of-way clearing.

Lease Payments for Excavator and Dump Truck

Scientific's late-filed Exhibit 6 was a quotation from Bobcat of Wilmington, Inc., for the lease of a backhoe at $645 per month, plus tax, for a five-year period. Also included among the late-filed exhibits is Exhibit 12, a 36-month equipment rental agreement between Priced Right Rentals (Lessor) and Scientific (Lessee) for the lease of a 2003 (used) GMC dump truck at $610 per month, which has been signed by Ben Aragona. However, the lease has not been signed by the lessor, and section 1 of the agreement specifically provides: "The term of this lease . . . commences on the date an authorized employee of Lessor executes and signs this lease." In view of this very specific language, the Commission must conclude that the lease is not now in effect, and there is no evidence in the record that Scientific has taken possession of the dump truck or made any payments under the lease.

In its proposed order, Scientific stated that the excavator and dump truck are items of equipment that are critical for adequate service to the customers but the Company does not have adequate funds to purchase these items. Scientific further stated that the Company is unable to purchase these items; however, if rates are granted in this proceeding to cover the annual lease costs, the Company committed that it would undertake the execution of these leases immediately.

As the Commission has previously discussed, anticipated future expenses cannot be treated as allowable operating expenses in a rate case unless they are known and measurable at the time the record is closed. This is a statutory mandate, not subject to waiver in the exercise of the Commission's discretion. Since Exhibits 6 and 12 are only quotations, rather than binding contracts, the Commission finds that the quoted lease payments cannot be deemed known and measurable as of the close of the record in this hearing and concludes that these items cannot be included in Scientific's operating expenses.

Lawn Mowing Service

No testimony was presented at the hearing as to the cost of lawn mowing service, and the list of future expenses in Exhibit 9 to Scientific's application did not include lawn mowing service. However, as late-filed Exhibit 7, Scientific provided an $8,800 quotation from Southern Landscaping & Grounds Inc., for mowing two well sites, four pump station sites and the wastewater treatment plant site bi-weekly from April through October. The exhibit is a quotation from Southern, not a contract executed by Scientific. Public Staff Aragona Cross-Examination Exhibit 1, a data response prepared by Scientific and admitted in evidence at the hearing, lists the duties of each of Scientific's employees, and it shows that employee Eladio Ramirez "[c]uts grass and weedeats at wastewater plant," while employee Kevin Popkin "[m]ows grass and weedeats at liftstations and wells."

The Commission concludes that a quotation from a potential vendor, as opposed to an executed contract for definitive services, cannot be deemed known and measurable as of the close of the record in this hearing and therefore should not be included in Scientific's operating expenses used to establish rates in this proceeding. Pursuant to G.S. 62-133(c), it is not appropriate to allow planned future expenses in operating expenses used to establish rates.

The Commission further finds that Scientific did not address how the duties of the employees currently performing the lawn mowing for the Company would be impacted if this function were contracted out. The Commission further concludes that the inclusion in operating expenses of a proposed payment to a contractor for work currently being performed by Company employees would result in a double recovery, which is not appropriate.

Backflow Preventers

On Schedule 8 of its application, the Company included an estimate of $300,000 for six backflow preventers plus meter and vault, which it included as a plant addition in rate base. In his prefiled rebuttal testimony, Company witness Hughes testified that the County is requiring backflow preventers and that the cost to install these preventers could be as much as $300,000. Witness Hughes further stated that this cost should not be capitalized, but rather should be paid for through a surcharge. At the hearing, Witness Hughes testified that the backflow preventer issue was part of another Scientific docket before the Commission that had not been consolidated with this proceeding. In its revised Dennis Exhibit I, the Company included $100,000 in maintenance and repairs, with the following note: "Six backflow preventers, plus meter and vault - To be treated as a pass-through item and amortized over three years."

These backflow preventers are the subject of Docket No. W-176, Sub 34, currently pending before the Commission. In that docket Scientific has requested the Commission to rule that Scientific cannot be required to comply with the Onslow County ordinance requiring backflow preventers. The backflow preventers have not yet been installed, either during the test period or since then; Scientific has not yet begun installing them or entered into a contract to install them; and it is not yet certain that Scientific will be required to install them. Under these circumstances, the Commission concludes that the installation of the backflow preventers cannot be considered a known and measurable change to test year expenses.

Pump Rebuilding Costs

Public Staff witness Tweed testified that the Company had expensed the cost of rebuilding several sewer pumps and motors during 2004. He recommended that Scientific capitalize these costs in the future, using a five-year life, as is normally done for ratemaking purposes. He recommended including in this proceeding, as a representative annual level of pump replacement costs, a three-year average cost calculated as follows:

2002	$5,290
2003	$4,899
2004	$9,897
3-year average	$6,695

Scientific did not take issue with witness Tweed's adjustment at the hearing. However, as late-filed Exhibit 15, Scientific presented an invoice from Capital Machinery Service & Supply, dated June 1, 2005, for a four-inch trash pump, motor, and related equipment and installation in the amount of $6,468.31. Scientific represented that this was a surge tank pump and asserted that another $3,000 needs to be added to the total for installation of piping, valves, T's and other extra materials. No documentation was provided for the additional $3,000 cost. In its final schedules filed on November 21, 2005, Scientific included $9,468 for the surge tank pump in plant additions.

Witness Tweed recommended an average level of $6,695 of pump replacement costs for the three-year period 2002-2004. If the Commission now includes $6,468 for 2005 and calculates the four-year average, there will be a slight reduction to the amount recommended by witness Tweed.

The Commission concludes that the three-year average recommended by witness Tweed is representative of the ongoing level of pump replacement costs and is appropriate for use in this proceeding.

Sewer Jet Lease

Company witness Aragona testified that the Company is required by the state to clean 10 percent of its sewer lines each year; that he would have to buy a sewer jet or hire out the cleaning; and that he would provide an estimate of the cost within a week or two.

As late-filed Exhibit 14, the Company presented two separate lease-purchase proposals for a $43,916 sewer jet unit, one from Cornerstone Leasing, LLC, and one from First Continental Leasing. The two proposals included options for payments from 36 to 60 months. Neither proposal was an executed agreement, and the Company indicated that the current rates do not provide funds to allow for the lease or purchase of a sewer jet. In its final accounting schedules the Company included $11,504 for a sewer jet lease, representing 12 months of payments under the Cornerstone lease proposal, using a 60-month lease term.

Company late-filed Exhibit 16 is a quotation from Ray's Septic Service, offering to provide pump station cleaning for $130 per 1,000 gallons and line cleaning for $100 per hour. The exhibit does not show how many hours it would take to perform any needed services, and the record does not show how much, if any, of this type of work was performed by the Company during the test year through its own employees.

Schedule 8 of revised Dennis Exhibit I, the list of capital improvements needed in the future, includes $15,000 for "Sewer Jet Building Repair." The reference to a "sewer jet building" suggests that there may be an existing sewer jet, which may perhaps have been used to clean lines during the test year, but the record is completely silent as to whether this in fact occurred.

As explained in the discussion of Finding of Fact No. 7 above, future capital improvements, such as those listed in Schedule 8 to the application, cannot lawfully be included in rate base or in the plant in service account, and planned future expenses cannot be lawfully be allowed as operating expenses. The Commission concludes that having an estimate for the cost of a piece of equipment or service is simply not a sufficient basis to enable inclusion of the equipment or service in rates.

Right-of-Way Clearing

Company witness Aragona testified that the Company is required by the state to clear the right-of-ways for its sewer lines. On its application, the Company included a capital expenditure of $60,000 for right-of-way clearing on Schedule 8, and a pro forma adjustment of $20,000 to maintenance and repairs expense for right-of-way clearing. After the hearing, the Company provided as late-filed Exhibit 2 a proposal from Eastern Excavating, Inc., to clear all sewer lift stations and gravity feed right-of-ways in the Raintree, Cedar Creek and Lauradale Acres subdivisions and perform road repair in the Deerfield subdivision for a lump sum price of $58,400. In its revised Dennis Exhibit I, the Company removed right-of-way clearing from its estimated capital improvements listed on Schedule 8, and instead included $58,400 in maintenance and repairs for right-of-way clearing.

The proposal filed by the Company as late-filed Exhibit 2 is very vague; it provides no detail regarding how many feet of clearing is required, whether the clearing is to be performed in heavily wooded areas or open areas, whether it includes any force main right-of-way clearing or only gravity mains, and how much of the lump-sum price is for road repair rather than right-of-way clearing. There is also insufficient information to determine how much of the estimated cost would be a one-time cost due to the fact that the Company has not cleared right-of-ways for years, and how much would be an annual expense once the right-of-ways are cleared.

The Commission concludes that the proposed expenditure relating to right-of-way clearing cannot be included in plant in service under Chapter 62 of the North Carolina General Statues. As previously pointed out in the discussion of Finding of Fact No. 7, North Carolina law does not permit the inclusion of future capital expenditures in rate base or in plant in service. As with the other proposed capital expenditures in Schedule 8 to the application, the Company is responsible for obtaining the necessary investment funding – whether from its operations, from a lender, from an equity investor, or through the sale of the system. Once the Company is able to begin work on right-of-way clearing, the costs can be included in plant in service or recognized as operating expenses, depending on the circumstances, in a future rate case.

Summary

Based on the foregoing, the Commission concludes that the appropriate level of maintenance and repairs for use in this proceeding is $36,698, consisting of $6,561 for purchased water operations, $5,001 for produced water operations, and $25,136 for sewer operations.

PROFESSIONAL FEES

The difference between Scientific and the Public Staff regarding professional fees relates to the inclusion of fees for work to be performed in the future by Company witnesses Dennis and Hughes as consultants for Scientific. In her prefiled testimony, Public Staff witness Stewart testified that the Company made a pro forma adjustment in its application to include $15,000 for professional fees, which she removed since the Company did not provide any documentation to support the adjustment.

In his prefiled rebuttal testimony, witness Dennis testified that he and witness Hughes had executed contracts with Scientific to provide professional services on an ongoing basis, and that each of the contracts was for an annual amount of $7,500. Witness Dennis attached partial copies of the contracts to his rebuttal testimony, and complete copies were filed as late-filed exhibits.

At the hearing, Public Staff witness Stewart testified that the consulting fees should not be included in expenses in this case, since they related to unknown work and amounts. She noted that some of the duties set forth in the contracts related to the potential sale of Scientific's system, and consulting fees relating to a sale should be taken out of the sales price rather than being recovered from customers as an expense. Witness Stewart further testified that any consulting work related to capital improvements would need to be treated as a capital cost rather than an operating expense. She stated that one of the consultants' duties listed in the contracts was identifying areas of cost savings to the Company, and any fees paid for these services should be offset by the cost savings.

Company witness Dennis testified that the consulting fees were not speculative; the contract rate is $100 per hour, and he anticipates that each consultant will be called on for at least 75 hours of work per year, resulting in annual billings of $7,500 per year. On cross-examination, witness Dennis agreed that the number of hours the consultants are called upon is up to Scientific, and there is no guarantee that they will have 75 hours of work per year. He acknowledged that if the consultants perform services in connection with a future rate case, their fees will be allowable as rate case expenses, and if they perform services in connection with an innovative ratemaking plan, the proper docket to consider those fees will be the docket in which the innovative plan is considered. Witness Dennis stated that he did not expect to do any work on the sale of Scientific's system, but he agreed that the contracts did not exclude work on a sale.

The Commission finds and concludes that the estimated consulting fees of $15,000 per year for witnesses Dennis and Hughes should not be included in operating expenses in this case. It is clear from witness Dennis's testimony that these expenses were not incurred in the test year and had not been incurred at the time of his testimony; instead, they are future expenses. It is impossible to determine at this time how much work the consultants will be asked to perform, or how much of their work will be recoverable in some other way – for example, as a rate case expense, as a capital cost, or out of the proceeds of a system sale. The expenses are speculative; they are not known and measurable as of the close of the hearing, and consequently they are not allowable.

RENT

In its application, the Company requested rent in the amount of $15,600 for combined operations. Public Staff witness Stewart stated in her prefiled testimony that since Scientific rented its office space and lot from Aragona Enterprises, an affiliated company, the transaction required special scrutiny to ensure that a reasonable rent was charged. Based on comparable rental properties in the area, witness Stewart recommended an annual level of rent of $11,699. Scientific did not present any evidence to contradict witness Stewart, either in rebuttal or during the hearing. During the hearing, witness Stewart was asked if she knew of the existence of an appraisal for the office that was presented in the last general rate case in 1998, and she replied that she had seen the document.

It is necessary to closely examine charges from affiliated companies since these transactions are at less than arm's length.[1] The utility bears the burden of showing the Commission that such charges are just and reasonable.[2] The Commission concludes that Scientific has not met its burden of proof that the rent charges at issue are just and reasonable. Scientific did not present any current data to support its level of rent, such as the actual cost of the facility being rented or current rental rates of comparable properties. The Commission notes that although counsel for Scientific made reference to an appraisal presented in the 1998 rate case, this appraisal was never filed with the Commission in the 1998 rate case, or in the present case. Therefore, the Commission concludes that the level of rent recommended by the Public Staff, which is based on current rental rates for comparable office space, is reasonable for use in this proceeding.

The Commission therefore concludes that the appropriate amount for annual combined rent should be $11,699.

TRANSPORTATION

On Schedule 8 to the application, the list of future capital improvements, the Company included $60,000 for two pickup trucks. At the hearing, witness Aragona testified that, due to the failing nature of the Company's current motor fleet, it is critical for operations that two new trucks be obtained. He further testified that the Company was getting price quotes on both purchasing and leasing the trucks, and that he thought that the Company would probably end up leasing the trucks for

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[1] *See State ex rel. Utils. Comm'n v. Morgan*, 7 N.C. App. 576, 588-89, 173 S.E.2d 479, 487-88 (1970) (Commission to examine closely transactions between utilities and affiliated companies to protect ratepayers from excessive rates), *rev'd on other grounds*, 277 N.C. 255, 177 S.E.2d 405 (1970), *adhered to on reh'g*, 278 N.C. 235, 179 S.E.2d 419 (1971).

[2] *Id.* at 588, 173 S.E.2d at 487; *Heater Utils. Inc.*, Order Granting Partial Rate Increase and Requiring Customer Notice, Docket No. W-274, Sub 478, p. 20 (Apr. 18, 2005).

approximately $348 per month for 36 months. No lease had been signed as of the time of the hearing.

The Company's late-filed exhibits include Exhibits 4 and 5, which are quotations from GMAC Commercial Services Group for the lease of two pickup trucks at $354.73 per month and $406.00 per month, respectively. The cover letter for the filing states that, under existing rates, Scientific lacks the creditworthiness to enter into these leases.

As the Commission has previously discussed in the context of other proposed adjustments, these transportation related proposals are anticipated future expenses and were neither known nor measurable at the time the record is closed. The Commission finds and concludes that since Exhibits 4 and 5 are only quotations, rather than binding contracts, the quoted lease payments cannot be deemed known and measurable as of the close of the record in this hearing, and they cannot be included in Scientific's operating expenses.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of operation and maintenance expenses for use in this proceeding is $842,274, consisting of $309,975 for purchased water operations, $106,883 for produced water operations, and $425,416 for sewer operations, as shown below.

Item	Purchased Water	Produced Water	Sewer
Administrative and office	$ 7,999	$ 4,070	$ 12,959
Chemicals	0	3,269	3,263
Electric power	0	3,942	49,128
Employee benefits	6,886	24,230	21,941
Insurance	3,594	1,829	6,076
Maintenance and repair	6,561	5,001	25,136
Other expenses	3,123	1,589	5,060
Penalties	6	2	8
Permit fees and licenses	0	1,475	860
Professional fees	3,368	1,713	5,457
Purchased water	203,211	0	0
Rate case expense	4,518	2,299	7,320
Rent	3,739	1,902	6,058
Salaries and wages	57,548	50,078	156,110
Sludge removal	0	0	96,771
Telephone & communications	2,722	1,385	5,623
Testing 3,374	2,307	18,258	
Transportation	3,326	1,692	5,388
Travel expenses	0	100	0
Total operation & maintenance exp.	$ 309,975	$106,883	$ 425,416

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 40 - 45

The evidence supporting these findings is contained in the testimony of Public Staff witness Stewart and Company witness Dennis. The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of depreciation and taxes to be used in this proceeding:

Item	Company	Public Staff	Difference
Depreciation expense	$ 65,222	$ 16,584	$ (48,638)
Property taxes	974	974	0
Payroll taxes	25,409	19,042	(6,367)
Regulatory fee	1,008	1,008	0
Gross receipts tax	42,106	42,105	(1)
State income tax	0	0	0
Federal income tax	0	0	0
Total depreciation and taxes	$ 134,719	$ 79,713	$ (55,006)

The Company did not dispute the Public Staff's recommended levels of property taxes and regulatory fee. Although there is a rounding difference of $1 between the levels of gross receipts tax recommended by the parties, the Company did not dispute the Public Staff's calculation of gross receipts tax. Therefore, the Commission finds and concludes that the levels recommended by the Public Staff for these items are appropriate for use in this proceeding.

DEPRECIATION EXPENSE

The difference between Scientific and the Public Staff regarding depreciation expense results from the parties' disagreement over the levels of plant in service, plant additions, and contributions in aid of construction. Based on the conclusions concerning plant in service, plant additions, and contributions in aid of construction reached elsewhere in this order, the Commission concludes that the amount of depreciation expense presented by the Public Staff is reasonable and appropriate for use in this proceeding.

PAYROLL TAXES

The parties are recommending different levels of payroll taxes due to their disagreement over the appropriate level of salaries and wages to include in this proceeding. Having previously determined the appropriate level of salaries and wages, the Commission concludes that the appropriate level of payroll taxes for use in this proceeding is $21,896, consisting of $4,758 for purchased water operations, $4,188 for produced water operations, and $12,950 for sewer operations.

STATE AND FEDERAL INCOME TAXES

The Public Staff calculated state and federal income taxes based on the consolidated taxable income for purchased water, produced water, and sewer operations, using the statutory corporate tax rates. The Company did not dispute the Public Staff's methodology in its rebuttal testimony or at the hearing. Therefore, the Commission concludes that state and federal income taxes should be calculated based on the taxable income for combined utility operations, and based upon conclusions reached elsewhere in this Order regarding the levels of revenues and expenses, The Commission finds and concludes that the appropriate level of state and federal income tax for use in this proceeding is $7,097 and $20,806, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 46 AND 47

The evidence supporting these findings is contained in the affidavit of Public Staff witness Craig, the testimony of Company witness Hughes, and the entire record in this proceeding.

The Company used the rate base method, which allows a return on rate base for the determination of the revenue requirement, in the schedules submitted with its application. Scientific's schedules showed that its rate base was larger than its operating revenue deductions. However, in its revised Dennis Exhibit I, the Company revised its calculation of the return for purchased water and sewer operations to the operating ratio method, since operating revenue deductions for these two operations were greater than rate base.

In his affidavit, Public Staff witness Craig recommended the use of the operating ratio method for determining the proper revenue requirement. This was based on the Public Staff's investigation in which it found that operating revenue deductions were substantially higher than rate base.

The Commission has examined the issues of revenue deductions and rate base in this proceeding and agrees with the Public Staff that operating revenue deductions are larger than rate base. Therefore, the Commission concludes that the operating ratio method is the proper approach for the determination of the revenue requirement.

Public Staff witness Craig recommended a margin of 8.50%, which was comprised of a risk-free rate of 5.50% plus a risk factor of 3.00%. His recommendation resulted in operating ratios of 92.69% (including taxes) and 92.17% (excluding taxes) for water operations and 92.85% (including taxes) and 92.17% (excluding taxes) for sewer operations. In his affidavit, he stated that his recommendation provided adequate income and ample coverage of Scientific's interest expense. He also pointed out that the owners of Scientific have a very minimal investment in the Company and, therefore, have extremely high debt leverage that exacerbates the owner's attempts at arranging financing for the Company. Scientific did not call Public Staff witness Craig to testify.

In its application filed on May 3, 2005, Scientific first proposed a margin of 10.00%. No rationale or explanation was provided with the application or in the Company's prefiled testimony. However, at the hearing it was brought out that Scientific's attorney had sent an e-mail to a Public Staff attorney which stated: "We have made this decision on the assumption that the Staff will recommend its normal 'risk-free rate plus risk premium' rate of return of eight to nine percent on rate base or 90 to 92 percent operating ratio in this case. If the Public Staff does so, we'll probably be in a position to stipulate. As I think I have told you Scientific's major concern in the case is not rate base or rate of return; it's simply having an overall revenue requirement and a set of rates that will produce a positive cash flow which we could use to induce banks to lend us money for the improvements that need to be made."

Company witness Hughes appeared to recommend a 10.50% margin in his rebuttal testimony. He testified that "[w]e need to raise the risk factor from 3 to 5." It can be assumed that witness Hughes accepted 5.50% as the risk-free rate and added 5.00% to it for a 10.50% margin. He stated: "We must take a hard look at what has to be done to achieve the overall results to ensure viability."

Generally, he opined that such a high return was needed to allow the Company to attract loans for capital improvements to the Company's system.

During cross-examination, Company witness Hughes was shown a schedule of Scientific's debt as of December 31, 2004. On this schedule, the Company had a total of $109,303 in various outstanding loans and reported that collateral was not required for $55,930 or 51% of the debt. However, Company witness Hughes said that witness Aragona personally guaranteed many of the Company's loans. On cross-examination, Company witness Aragona admitted that Scientific made a total of $11,304 in loans to five members of the Aragona family during 2003 and that these loans continued to be outstanding on December 31, 2004.

The Commission is very aware of Scientific's financial situation and the need to make repairs and improvements to its systems. The Company claims that it cannot attract capital at this time for various reasons. However, in 2004 at least, the Company had loans from several sources, with more than half of them not requiring collateral. In 2003 and 2004, if not today, Scientific had $11,304 in loans outstanding to the Aragona family. The recall of these loans by Scientific would help the cash flow of the Company. The owners' equity investment in Scientific is very minimal and there is not strong evidence of the owners' attempts to find additional equity investors.

In its revised Dennis Exhibit I and in its proposed order, Scientific accepted witness Craig's proposed 8.50% margin.

The Commission concludes that the overall margin of 8.50% on operating revenue deductions requiring a return recommended by the Public Staff and agreed to by the Company is just and reasonable for use in this proceeding. When coupled with other aspects of this rate increase, the 8.50% margin should allow the owners an opportunity to earn a reasonable return that should be viewed positively by lenders and new equity investors. This should result in additional funds to address the capital requirements of the system. Should the margin or other aspects of the rate increase become insufficient in the future, Scientific can file for additional rate increases and should do so more expeditiously than it has in the past.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 48

The following schedules summarize the gross revenue and rate of return that the Company should have a reasonable opportunity to achieve based upon the increase approved in this order. These schedules, illustrating Scientific's gross revenue requirements for its combined operations, incorporate the findings and conclusions reached by the Commission in this order.

SCHEDULE I

SCIENTIFIC WATER AND SEWERAGE CORPORATION
DOCKET NO. W-176, SUB 32
STATEMENT OF OPERATING INCOME AVAILABLE FOR RETURN
COMBINED OPERATIONS
For the Twelve Months Ended December 31, 2004

Item	Present Rates	Increase Approved	After Approved Increase
Operating revenues:			
Service revenues	$ 830,716	$ 198,010	$ 1,028,726
Other revenues	17,794	0	17,794
Bad debt expense	(8,467)	0	(8,467)
Total operating revenues	840,043	198,010	1,038,053
Operating revenue deductions:			
O&M expenses	842,274	0	842,274
Depreciation expense	16,584	0	16,584
Property taxes	974	0	974
Payroll taxes	21,896	0	21,896
Regulatory fees	1,008	237	1,245
Gross receipts tax	42,105	10,124	52,229
State income tax	0	7,097	7,097
Federal income tax	0	20,806	20,806
Total oper. revenue deduction	924,841	38,264	963,105
Net operating income for return	$ (84,798)	$ 159,746	$ 74,948
Operating revenue deductions requiring a return	$ 881,728		$ 881,728
Margin	-9.62%		8.50%

SCHEDULE II

SCIENTIFIC WATER AND SEWERAGE CORPORATION
DOCKET NO. W-176, SUB 32
STATEMENT OF RATE BASE
COMBINED OPERATIONS
For the Test Year Ended December 31, 2004

Item	Amount
Plant in service	$ 4,222,916
Plant additions	0
Accumulated depreciation	(296,007)
Contributions in aid of construction	(3,912,885)
Cash working capital	79,883
Average tax accruals	(11,154)
Original cost rate base	$ 82,753

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 49

The evidence supporting this finding is contained in the testimony of Public Staff witness Tweed. The Company did not contest Public Staff witness Tweed's rate design methodology. Therefore, based on the total annual revenues found reasonable elsewhere in this order and the rate design methodology proposed by the Public Staff, the Commission concludes that the rates set forth in the attached Schedule of Rates will allow the Company the opportunity to earn the 8.5% margin found reasonable in this order.

The Commission does note that on Schedules 3, 3(a), 3(b), and 3(c) of its revised Dennis Exhibit I, the Company listed revenues under proposed rates that were greater than the amounts requested in its application and noticed to customers. However, in Schedules 16, 17, and 18, the Company's proposed rates remained at the amounts set forth in its application, resulting in an inconsistency between the revenues from Company's proposed rates listed on Schedule 3 and the amounts on the Company's supporting schedules. As stated in the notice to customers, any rate structure granted by the Commission should not generate more overall revenues than requested by the Company in its application. Since the overall revenue requirement found reasonable by the Commission in this order is less that the total amount generated by the rates requested by the Company in its application, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 50

The evidence supporting this finding is contained in the testimony of Public Staff witness Tweed and is not contested by Scientific. The Commission therefore concludes that there should be no increase in reconnection fees.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

The evidence supporting this finding is contained in the application and the testimony of Public Staff witness Tweed. In its application the Company proposed to include in its tariff a standard deposit of $100 for customers who apply for service and have no previous usage history.

Witness Tweed testified that under Commission Rule R12-4(a), the deposit to be paid by a customer applying for service is limited to "two-twelfths of the estimated charge for service in the ensuing twelve months," and the rule does not provide for a fixed deposit amount for customers with no usage history. He stated that the deposit for a customer with no usage history should be limited to two-twelfths of the average annual bill for all the Company's other customers in the same class, i.e., metered residential customers. On cross-examination, witness Tweed stated that a deposit calculated according to his proposed method would not differ greatly from the Company's $100 figure; however, he noted that other utilities adhere to the Commission's rule and believed that Scientific should do so.

The Commission concludes that witness Tweed's proposed method of calculating a deposit for customers with no usage history is consistent with Rule R12-4(a) and that Scientific's proposal for a standard deposit of $100 should not be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence supporting this finding is contained in the testimony of Public Staff witness Tweed.

During its audit of Scientific's application, the Public Staff ascertained that Scientific had begun charging a convenience fee of $2.00 for customers who choose to pay their bills by credit card. Witness Tweed testified that he did not object to this charge, but he believed it should be included in the Company's tariff.

The Commission recognizes that there are costs associated with processing credit card payments and believes that a utility should be permitted to charge a fee for these payments if it desires to do so; however, the fee should be set out in the utility's tariff. The Commission finds that Scientific should not have implemented the fee unilaterally without obtaining Commission approval, but concludes that the Company's request to charge a $2.00 fee should be approved and included on the Company's tariff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53 AND 54

The evidence supporting these findings is contained in the testimony of Public Staff witness Tweed and the entire record in this proceeding and in the proceedings in Docket No. W-176, Subs 29 and 30.

Docket No. W-176, Sub 30

This docket involves the Company's last general rate case proceeding in 2000. The docket has remained open due to required service improvements and reporting requirements. The unresolved issues in that docket involve virtually the same DEH and DWQ compliance issues that are being addressed in this Sub 32 case.

The Commission therefore concludes that there is no need for the Sub 30 docket to remain open.

Docket No. W-176, Sub 29

In Docket No. W-176, Sub 29, Scientific notified the Commission of a contiguous extension of sewer only service into Maynard Manor subdivision. The Commission has not yet required, and Scientific has not yet posted, any bond for this contiguous extension. The Sub 29 docket remains open and has been consolidated with this general rate case.

This issue is controlled by G.S. 62-110.3(c), which provides in pertinent part:

> [N]o water or sewer utility shall extend service into territory contiguous to that already occupied without first having advised the Commission of such proposed extension. Upon notification, the Commission shall require the utility to furnish an appropriate bond, taking into consideration both the original service area and the proposed extension. This subsection shall apply to all service areas of water and sewer utilities without regard to the date of the issuance of the franchise.

In 2002, the Public Staff filed a motion in Subs 29 and 30 recommending a moratorium on new connections, pending certain improvements, and a $130,000 bond based upon the then estimated cost to bring the water and sewer systems into compliance with DEH and DWQ regulations. Because of delays resulting from a proposed sale of the system to the City of Jacksonville and other factors, the Commission has never ruled on the Public Staff's motion. In the current case, the Public Staff is no longer seeking a moratorium, but is again recommending a $130,000 bond, contending that this is a reasonable, and perhaps considerably understated, estimate of the amount of funding that would be required for an emergency operator if one is needed for Scientific's system.

While Scientific appears to allege that posting a $130,000 bond will adversely impact its ability to obtain funds needed to upgrade the systems, no evidence has been introduced to support that contention. Scientific also notes that, since it was already in existence at the time the bonding requirement became law, it has been "grandfathered" or exempt from posting a bond for its facilities. The Commission has a statutory obligation to establish a bond, however, in an appropriate amount considering the statutory guidelines, and, as the statute makes clear, Scientific cannot be exempt or "grandfathered" from furnishing a bond for its contiguous extension into Maynard Manor.

The Commission concludes that Scientific should be required to post a $130,000 bond, after which an order should be issued acknowledging the contiguous extension into the Maynard Manor subdivision.

IT IS THEREFORE, ORDERED as follows:

1. That Scientific shall adjust its water and sewer rates and charges to produce, based on the adjusted test year level of operations, an increase in its annual revenues of $38,171 for its purchased water operations, $49,699 for its produced water operations, and $110,140 for its sewer operations.

2. That the Schedule of Rates, attached hereto as Appendix B, is approved for water and sewer utility service rendered by Scientific. These rates shall become effective for service rendered on and after the effective date of this order. This schedule is deemed filed with the Commission pursuant to G.S. 62-138.

3. That a copy of the Notice to Customers, attached hereto as Appendix C, shall be delivered by Scientific to all its customers in conjunction with the next billing statement after the effective date of this order.

4. That Scientific shall, within 60 days following the date of this order, file a report addressing the specific steps to be taken regarding the following improvements to its water and sewer systems, with the detailed cost and estimated timeframe for completion of each step:

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.

b. Construction and rehabilitation of the existing and new sludge holding facilities, including the ability to thicken the sludge.

c. Removal of accumulated sludge from the polishing ponds and drying bed area.

d. Providing DWQ approved, operable alarm systems at the wastewater treatment plant and all sewer pump stations.

e. Rebuilding the facilities at the Deerfield sewer pump station.

f. Installing a generator at the Maynard Manor sewer pump station.

g. Repair or replacement of the influent bar screen at the wastewater treatment plant.

h. Repair of clogged or blown air diffusers at the wastewater treatment plant.

i. Installation of a fence around the sludge drying facilities, unless the facilities are slated for abandonment.

5. That Scientific shall, within six months from the date of this order, file a progress report showing the status of the projects including obtained funding and the timeframe for completion of the improvements listed in paragraph 4 above.

6. That Scientific shall post a bond in the amount of $130,000 in connection with the extension of sewer service in Maynard Manor, Docket No. W-176, Sub 29. Scientific shall complete one of the attached bonds (Appendices A-1, A-2, or A-3) and <u>return said bond to the Commission</u>. Additionally:

a. If the bond selected is Appendix A-1, Scientific shall deposit the appropriate surety in the amount of $130,000 with SunTrust Bank, Attention: Rebecca Brock, Trust Administrator, 4101 Lake Boone Trail, Suite 111, Raleigh, North Carolina 27607.

b. If the bond selected is Appendix A-2, Scientific shall file the letter of credit surety and commitment letter (see Filing Requirements for Bonding, Appendix A-4) with the Commission. The letter of credit shall contain the following language <u>verbatim</u>:

If for any reason the Letter of Credit is not to be renewed upon its expiration, the Bank shall, at least 60 days prior to the expiration date of the Letter of Credit, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Letter of Credit will not be renewed beyond the then current maturity date for an additional period. Failure to renew the Letter of Credit shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Letter of Credit to cash and deposit said cash proceeds with the administrator of the Commission's bonding program. Said cash proceeds from the converted Letter of Credit shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission's Rules R7-37(e) and/or R10-24(e).

c. If the bond selected is Appendix A-3, Scientific shall file the power of attorney and commitment letter (see Filing Requirements for Bonding, Appendix A-4) with the Commission.

7. That upon Commission approval of the bond, surety and commitment letter, a further order shall be issued recognizing the contiguous extension into the Maynard Manor subdivision in Onslow County, North Carolina.

8. That Docket No. W-176, Sub 30, is closed.

ISSUED BY ORDER OF THE COMMISSION.
This the _10th_ day of _February_, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh021306.01

NCUC DOCKET NO. W-176, SUB 29 **APPENDIX A-1**

BOND

______________________________________ of ____________________,
(Name of Utility) (City)
________________________________, as Principal, is bound to the State of North
(State)
Carolina in the sum of ______________________________ Dollars ($__________)
and for which payment to be made, the Principal by this bond binds himself, his, and its successors and assigns.

THE CONDITION OF THIS BOND IS:

WATER AND SEWER – RATE INCREASE

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water or sewer utility ______________________________

____
(describe utility)
______________________________ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in G.S. § 62-110.3, and Commission Rules R7-37 and/or R10-24, and,

WHEREAS, the Principal has delivered to the Commission ______________________________

____
(description of security)
with an endorsement as required by the Commission, and,

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, this bond shall become effective on the date executed by the Principal, and shall continue from year to year unless the obligations of the Principal under this bond are expressly released by the Commission in writing.

NOW THEREFORE, the Principal consents to the conditions of this Bond and agrees to be bound by them.

This the ____________ day of ____________________ 20___.

____
(Name)

NCUC DOCKET NO. W-176, SUB 29 **APPENDIX A-2**

BOND

______________________________ of ______________________________,
(Name of Utility) (City)
______________________________, as Principal, is bound to the State of North Carolina in the sum of
(State)
______________________________ ____________ Dollars ($____________)
and for which payment to be made, the Principal by this bond binds __________ and __________ successors and assigns.
(himself)(itself) (his)(its)

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water and/or sewer utility __________

____
(describe utility)
______________________________ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water and/or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in G.S. § 62-110.3, and Commission Rules R7-37 and/or R10-24, and

WHEREAS, the Principal has delivered to the Commission an Irrevocable Letter of Credit from ______________________________

(Name of Bank)

with an endorsement as required by the Commission, and,

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, if for any reason, the Irrevocable Letter of Credit is not to be renewed upon its expiration, the Bank shall, at least 60 days prior to the expiration date of the Irrevocable Letter of Credit, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Irrevocable Letter of Credit will not be renewed beyond the then current maturity date for an additional period, and

WHEREAS, failure to renew the Irrevocable Letter of Credit shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Irrevocable Letter of Credit to cash and deposit said cash proceeds with the administrator of the Commission's bonding program, and

WHEREAS, said cash proceeds from the converted Irrevocable Letter of Credit shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e), and

WHEREAS, this bond shall become effective on the date executed by the Principal, and shall continue from year to year unless the obligations of the Principal under this bond are expressly released by the Commission in writing.

NOW THEREFORE, the Principal consents to the conditions of this Bond and agrees to be bound by them.

This the __________ day of ________________ 20___.

____
(Principal)

BY: ______________________________

NCUC DOCKET NO. W-176, SUB 29 **APPENDIX A-3**

BOND

______________________________ of ______________, ______________,
(Name of Utility) (City) (State)
as Principal, and ______________________________, a corporation created and existing under
(Name of Surety)
the laws of ______________________________, as Surety (hereinafter called "Surety"), are
(State)
bound to the State of North Carolina in the sum of ____________ Dollars ($________) and for which payment to be made, the Principal and Surety by this bond bind themselves and their successors and assigns.

WATER AND SEWER – RATE INCREASE

THE CONDITION OF THIS BOND IS:

WHEREAS, the Principal is or intends to become a public utility subject to the laws of the State of North Carolina and the rules and regulations of the North Carolina Utilities Commission, relating to the operation of a water and/or sewer utility ____________

____

(Describe utility)

____ and,

WHEREAS, North Carolina General Statutes § 62-110.3 requires the holder of a franchise for water and/or sewer service to furnish a bond with sufficient surety, as approved by the Commission, conditioned as prescribed in § 62-110.3, and Commission Rules R7-37 and/or R10-24, and

WHEREAS, the Principal and Surety have delivered to the Commission a Surety Bond with an endorsement as required by the Commission, and

WHEREAS, the appointment of an emergency operator, either by the Superior Court in accordance with G.S. § 62-118(b) or by the Commission with the consent of the owner, shall operate to forfeit this bond, and

WHEREAS, if for any reason, the Surety Bond is not to be renewed upon its expiration, the Surety shall, at least 60 days prior to the expiration date of the Surety Bond, provide written notification by means of certified mail, return receipt requested, to the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325, that the Surety Bond will not be renewed beyond the then current maturity date for an additional period, and

WHEREAS, failure to renew the Surety Bond shall, without the necessity of the Commission being required to hold a hearing or appoint an emergency operator, allow the Commission to convert the Surety Bond to cash and deposit said cash proceeds with the administrator of the Commission's bonding program, and

WHEREAS, said cash proceeds from the converted Surety Bond shall be used to post a cash bond on behalf of the Principal pursuant to North Carolina Utilities Commission Rules R7-37(e) and/or R10-24(e), and

WHEREAS, this bond shall become effective on the date executed by the Principal, for an initial ____ year term, and shall be automatically renewed for additional _____________ (No. of Years)

(No. of Years)

year terms, unless the obligations of the principal under this bond are expressly released by the Commission in writing.

NOW, THEREFORE, the Principal and Surety consent to the conditions of this bond and agree to be bound by them.

This the ____________ day of ________________________ 20___.

____

(Principal)

BY: ____________________________

____

(Corporate Surety)

BY: ____________________________

APPENDIX A-4

Filing Requirements for Bonding

Type of Bond

	Cash / Certificate of Deposit Bond	Irrevocable Letter of Credit Bond	Commercial Surety Bond
Bond A-1	X 1/		
Bond A-2		X 1/	
Bond A-3			X 1/
Cash / CD	X 2/		
Letter of Credit		X 3/	
Power of Attorney			X 4/
Commitment Letter		X 5/	X 5/

(To be filed with the Chief Clerk - where applicable)

1/ Original Copy of the Bond - Preferably on the forms prescribed in the Commission Order dated July 19, 1994, in Docket No. W-100, Sub 5 (Bond forms are usually attached to Order Requiring Bond for each specific franchise).

2/ Notification from SunTrust Bank (SunTrust is the Commission's custodian for bond sureties) that cash or CD surety has been received for a given bond.

3/ Original Copy of Non-Perpetual Irrevocable Letter of Credit [Letter of Credit must comply with Rule R7-37 New Section (e)(4) as adopted by the Commission in its Order dated July 19, 1994, In Docket No. W-100, Sub 5.]

4/ Original Copy of Power of Attorney for individual who signed Appendix A-3 as Corporate Surety

5/ Original Copy of Commitment Letter

(a) This letter need only contain a statement indicating whether the utility is required to pledge utility company assets (collateral and type) to secure the bond or irrevocable letter of credit; and

(b) The premium paid by the utility (if any) to the bank and/or lending institution for their accommodation of the borrower.

APPENDIX B
PAGE 1 OF 3

SCHEDULE OF RATES

for

SCIENTIFIC WATER AND SEWERAGE CORPORATION

for providing water and sewer utility service in

ALL ITS SERVICE AREAS

in

Onslow County, North Carolina

WATER UTILITY SERVICE:

Flat Rate Water: Lauradale Water System	
(Water produced from Scientific's wells)	
One bedroom apartments, Lee Garden	$15.51
Two bedroom apartments, Lauradale	$18.09
Metered Water: Lauradale Water System	
(Water produced from Scientific's wells)	
Base charge per month, zero usage	$ 7.35
Usage charge, per 1,000 gallons	$ 2.34
Metered Water: Cedar Creek, Raintree, Deerfield, and Summersill Systems	
(Water purchased from Onslow County)	
Base charge per month, zero usage	$ 9.37
Usage charge, per 1,000 gallons	$ 3.43

SEWER UTILITY SERVICE:

Flat Rate Sewer: Residential and Commercial	$25.87
Metered Rate Commercial Sewer	
Base charge per month, zero usage	$12.62
Usage charge, per 1,000 gallons	$ 2.52

APPENDIX B
PAGE 2 OF 3

OTHER RATES AND CHARGES:

Connection Charge: (Residential)	Water	Sewer
Cedar Creek	$150	$150
Raintree	$300	$300
Summersill	$300	$965.43 for total of 100 connections after which the fee shall be $450
All Other Service Areas	$250	$450

Connection Charge:
(Commercial sewer) $3.00 per gallon per day of design flow as determined by the Department of Environment and Natural Resources' design flow criteria.

Monthly Surcharge (per bill)[1]	$0.60
Credit Card Convenience Fee:	$2.00

Reconnection Charge: (during normal business hours)

If water cut off by utility for good cause	$15.00
If water discontinued at customer's request	$15.00

Reconnection Charge: (after normal business hours, and on Saturday, Sunday and holidays)

If water cut off by utility for good cause	$30.00
If water discontinued at customer's request	$15.00

[1] Pursuant to Docket No. W-176 Sub 33, the $0.60 monthly surcharge is to pay for an engineering study required by the City of Jacksonville to accommodate the potential transfer of the water and sewer systems to the City. The surcharge shall cease at the earlier of: (a) collection of the full amount of the surcharge as reflected in the engineering agreement or (b) Commission approval of a transfer of the systems.

APPENDIX B
PAGE 3 OF 3

Reconnection Charge: (Sewer-only utility service)

If sewer service is disconnected by the utility for good cause: Actual Cost

(The customer must pay all delinquent bills to avoid disconnection, or to initiate a reconnection. Prior to physically disconnecting sewer service, a written statement of the estimated "actual cost" of disconnection, plus reconnection, of the sewer collection lines will be delivered or mailed to the customer with the Cut-off Notice.)

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

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Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-176, Sub 32, on this the 10th day of February, 2006.

APPENDIX C

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-176, SUB 32

Notice is given that the North Carolina Utilities Commission has granted a rate increase to Scientific Water and Sewerage Corporation (Scientific) for water and sewer utility service in all its service areas in Onslow County, North Carolina. This decision was based on evidence presented at the public hearings held on August 30 and 31, 2005, in Jacksonville, North Carolina.

The new rates are as follows:

WATER UTILITY SERVICE:

Flat Rate Water: Lauradale Water System

(Water produced from Scientific's wells)

One bedroom apartments, Lee Garden	$15.51
Two bedroom apartments, Lauradale	$18.09

Metered Water: Lauradale Water System	
(Water produced from Scientific's wells)	
Base charge per month, zero usage	$ 7.35
Usage charge, per 1,000 gallons	$ 2.34
Metered Water: Cedar Creek, Raintree, Deerfield, and Summersill Systems	
(Water purchased from Onslow County)	
Base charge per month, zero usage	$ 9.37
Usage charge, per 1,000 gallons	$ 3.43
SEWER UTILITY SERVICE	
Flat Rate Sewer: Residential and Commercial	$25.87
Metered Rate Commercial Sewer	
Base charge per month, zero usage	$12.62
Usage charge, per 1,000 gallons	$ 2.52

The Commission also directed Scientific to take a variety of steps to improve the quality of its service and repair its water and sewer systems. Scientific was directed to file reports with the Commission within 60 days, and again within six months, on the progress it has made in carrying out these steps.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of February, 2006.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

(SEAL)

DOCKET NO. W-1000, SUB 11

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Hydro Star, LLC	)	ORDER APPROVING
to Acquire the Outstanding Stock	)	ACQUISITION OF STOCK AND
of Utilities, Inc.	)	REQUIRING CUSTOMER NOTICE

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on February 21, 2006 at 10:30 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners Sam J. Ervin IV and William T. Culpepper III

APPEARANCES:

For Utilities, Inc. and Hydro Star, LLC:

Edward S. Finley, Jr., Hunton & Williams, Post Office Box 109, Raleigh, North Carolina 27602

For the Town of North Topsail Beach, Herschell E. Godwin, Jr., and the Saint Moritz Homeowners Association:

M. Gray Styers, Jr., Blanchard, Jenkins, Miller, Lewis & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

For the Using and Consuming Public

William Grantmyre and Ralph Daigneault, Staff Attorneys, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On August 18, 2005, Utilities Inc., which includes all of its subsidiaries, and Hydro Star, LLC ("Hydro Star"), (collectively, "Applicants"), filed an application seeking Commission approval of the acquisition of the stock of Utilities, Inc., from Nuon Global Solutions USA, BV, pursuant to N.C. Gen. Stat. § 62-111, in accordance with the Stock Purchase Agreement filed as a confidential exhibit to the application.

Beginning September 12, 2005, the Public Staff served extensive data requests on the Applicants to determine whether the proposed stock transfer would be justified by the public convenience and necessity.

By order issued October 12, 2005, the Commission required public notice of the application and indicated that the matter could be determined without public hearing if no significant protests were received.

On November 28, 2005, the St. Moritz Homeowners Association and Herschell E. Godwin, Jr. filed a Petition to Intervene. On December 7, 2005, Applicants filed a response to this petition to intervene.

On December 9, 2005, the Town of North Topsail Beach filed a Petition to Intervene. On December 20, 2005, the North Topsail Intervenors filed a reply to Applicants' December 7, 2005 response.

On January 12, 2006, the Commission granted the Petitions to Intervene by the St. Moritz Homeowners Association and Herschell E. Godwin, Jr. and the Town of North Topsail Beach.

On January 18, 2006, the Commission scheduled a hearing and required customer notice.

On January 20, 2006, the Applicants pre-filed the written testimony of Aaron D. Gold, Principal for AIG Highstar Capital II GP, L.P. and Steven M. Lubertozzi, Director of Regulatory Accounting for Utilities, Inc.

On February 2, 2006, Hound Ears Club, Inc. filed a Petition to Intervene.

On February 3, 2006, Magnolia Plantation Partnership filed a Petition to Intervene.

On February 3, 2006, a stipulation was entered into between the Applicants and the Public Staff that resolved the issues between these parties.

On February 3, 2006, the Public Staff pre-filed the written direct testimony of Katherine A. Fernald, Supervisor of the Water Section of the Public Staff – Accounting Division, and Gina Y. Casselberry, a Utilities Engineer with the Public Staff – Water Division.

On February 3, 2006, the Commission granted the Petition to Intervene of Hounds Ears Club, Inc.

On February 6, 2006, Lancaster County Water and Sewer District filed a Petition to Intervene.

On February 6, 2006, the Town of North Topsail Beach pre-filed the written direct testimony of James Roderick Butler, a professional engineer, Mayor W. Rodney Knowles and Alderman Daniel Tuman.

On February 6, 2006, Herschell E. Godwin, Jr., intervenor and resident of North Topsail Beach, pre-filed direct written testimony.

On February 9, 2006, Applicants filed responses to the Magnolia Plantation Partnership and Lancaster Water and Sewer District's intervention requests.

On February 14, 2006, the Commission granted the Petitions to Intervene of Lancaster County Water and Sewer District and Magnolia Plantation Partnership.

On February 14, 2006, the Applicants pre-filed rebuttal testimony of Carl Daniel, Vice President and Regional Director of Operations for Carolina Water Service, Inc. of North Carolina, and Steven Lubertozzi.

On February 21, 2006, Magnolia Plantation Partnership and Lancaster County Water and Sewer District filed notices of withdrawal of their petitions to intervene.

On February 21, 2006, Hound Ears Club informed the Commission of its withdrawal of its petition to intervene.

On February 21, 2006, a stipulation was entered into between Applicants and the Town of North Topsail Beach and the other North Topsail Intervenors resolving the issues between these parties. This stipulation was presented to the Commission for its consideration. The North Topsail Intervenors withdrew the pre-filed testimonies of James Roderick Butler, Mayor W. Rodney Knowles, Alderman Daniel Tuman and Herschell Godwin. The Applicants withdrew the rebuttal testimony of Carl Daniel and Steven Lubertozzi, as this rebuttal testimony only addressed issues relating to North Topsail.

The matter came on for public hearing on February 21, 2006. Aaron Gold and Steven Lubertozzi testified on behalf of the Applicants in support of the application. Katherine Fernald and Gina Casselberry testified on behalf of the Public Staff and in support of the joint stipulation. Also testifying as public witnesses were: Hugh McCain and Robert Wemyss from Monteray Shores, Vincent Roy and Stewart L. Aiken from Carolina Trace, James Alexy from Corolla Light, Frank Rutherford from Fairfield Mountains and Charles Lubrecht from Carolina Pines.

The stipulation submitted by the Applicants and the Public Staff settled the issues between them and requested that the transfer of the outstanding stock be approved immediately, subject to the following provisions and conditions:

1. All records of Utilities, Inc. will be physically available as required by North Carolina law.

2. Hydro Star will comply with any Commission requirement that Utilities, Inc. personnel familiar with the company records be reasonably available in North Carolina.

3. The Applicants will not seek recovery of losses or subsidization of non-utility subsidiaries of Hydro Star or Utilities, Inc. from North Carolina customers.

4. The officers and management of Utilities, Inc. will have reasonable authority to commit Utilities, Inc., and its North Carolina regulated subsidiaries, on matters considered jurisdictional to the Commission.

5. The Applicants will seek Commission permission before a corporate restructuring of Utilities, Inc.

6. No franchise of Utilities, Inc., or any of its North Carolina regulated subsidiaries, now existing or hereafter issued by the Commission under the provisions of the Public Utilities Act of North Carolina, shall be sold, assigned, pledged or transferred, nor shall control thereof be changed

through stock transfer or otherwise, or any rights thereunder leased, nor shall any merger or combination, including Hydro Star and/or Utilities, Inc., affecting Utilities, Inc. and/or any of its North Carolina regulated subsidiaries, be made through acquisition of control by stock purchase or otherwise, except after application to and written approval by the Commission.

7. Hydro Star and Utilities, Inc. agree to be bound by North Carolina law and Commission Orders and rules and regulations as they relate to Utilities, Inc.'s North Carolina regulated subsidiaries.

8. All costs of the acquisition incurred by Hydro Star and/or Utilities, Inc., including compensation costs, and all direct and indirect corporate cost increases for Utilities, Inc. or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of Utilities, Inc.'s subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that Utilities, Inc. would have incurred using prudent business judgment had the acquisition not occurred.

9. All costs of the 2002 merger approved by the Commission in Docket No. W-1000, Sub 9, incurred by nv Nuon and/or Utilities, Inc., including compensation costs, and all direct and indirect corporate cost increases for Utilities, Inc. or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of Utilities, Inc.'s subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that Utilities, Inc., would have incurred using prudent business judgment had the merger not occurred.

10. Future payments to officers for annual bonuses, incentive bonuses, long term incentive bonuses, and any other bonuses made in relation to the acquisition will be excluded from Utilities, Inc.'s utility accounts and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of Utilities, Inc.'s subsidiaries.

11. Base salaries, compensation payments, annual bonuses, incentive bonuses, long term incentive bonuses, any other bonuses, and any incentive compensation other than those listed in Item 10 above shall be subject to review and ratemaking adjustment in future rate proceedings for Utilities, Inc., where Utilities, Inc. holds a Commission-issued certificate, and for its North Carolina regulated subsidiaries (including areas included within the certificate of such subsidiaries through operation of G.S. 62-110(a)). The burden of proof on each of these issues shall be upon Utilities, Inc., and its North Carolina regulated subsidiaries.

12. Any acquisition adjustment that results from the acquisition will be excluded from Utilities, Inc.'s utility accounts and treated for accounting and ratemaking purposes so that it does not affect water and sewer rates and charges of Utilities, Inc.'s subsidiaries.

13. Utilities, Inc. and each of its North Carolina regulated subsidiaries shall maintain its books and records so that its equity capital is recorded pursuant to the respective NARUC Uniform System of Accounts for Class A Water and Class A Wastewater Utilities, as revised in 1996, and all subsequent revisions.

14. Applicants shall provide Utilities, Inc., to the extent it holds certificates issued by the Commission, and its North Carolina regulated subsidiaries with sufficient access to equity and debt capital to enable Utilities, Inc. and its North Carolina regulated subsidiaries to adequately fund and maintain their current and future water and wastewater systems, and otherwise meet the service needs of their customers at a reasonable cost. The timing and quantity of any capital expenditures or discrete capital infusion shall be determined by the Applicants' best judgment consistent with the requirement to maintain the current and future water and wastewater systems and otherwise meet the service needs of the customers at a reasonable cost.

15. The Applicants agree to file all proposed amendments, updates, and new contracts pertaining to affiliated transactions with the Commission and get approval for the North Carolina operating subsidiary to pay compensation to an affiliate in advance of effectiveness as required under North Carolina General Statute 62-153.

16. The Applicants and all affiliates shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases and/or any other adverse effects of the transfer.

17. The books and records of Hydro Star and any other affiliated companies will be made available for inspection as required under North Carolina General Statute 62-51.

18. Utilities, Inc.'s North Carolina operating subsidiaries and Utilities, Inc., where it holds certificates from the Commission, shall comply with the requirements of G.S. 62-153 with respect to the procurement of goods or services from Hydro Star or other affiliated or subsidiary companies or entities. Whenever Utilities, Inc.'s North Carolina operating subsidiaries and Utilities, Inc., where it holds certificates from the Commission, seek to recover through rates the costs of goods or services procured from Hydro Star or other affiliated or subsidiary companies or entities, or whenever the Commission requires it, Utilities, Inc., shall have the burden of persuasion and proof as to the reasonableness of such costs in accordance with North Carolina law.

19. Utilities, Inc.'s operations in North Carolina are generally in compliance with applicable environmental regulations. In cases where Utilities Inc.'s affiliates are involved in environmental compliance issues, Utilities, Inc. and Hydro Star agree to continue to cooperate with all regulatory agencies in addressing any outstanding compliance issues, to the satisfaction of the environmental regulatory agencies and the Public Staff.

20. Utilities, Inc., through the appropriate operating subsidiary, shall use its best reasonable efforts to resolve the customer service complaints filed in the Commission's official file in this docket as of the close of the hearing or presented at the hearing from Corolla Light/Monteray Shores consumers in regard to water supply and chloride and trihalomethane levels. Utilities, Inc. shall file monthly progress reports with the Commission addressing water supply and chloride and elevated trihalomethane levels until such time that the Commission orders that filing the reports is no longer necessary. The first report shall be filed within 30 days from the date Applicants provide the Commission notice of the closing of the acquisition.

21. Utilities, Inc., through the appropriate operating subsidiary, shall use its best reasonable efforts to address the wastewater capacity and expansion complaints filed in the Commission's official file in this docket as of the close of the hearing or presented at the hearing

from North Topsail Beach consumers. Utilities, Inc. shall file with the Commission monthly progress reports addressing wastewater capacity and expansion_until such time that the Commission orders that filing the reports is no longer necessary. The first report shall be filed within 30 days of the date Applicants provide the Commission notice of the closing of the acquisition.

22. Utilities, Inc., through the appropriate operating subsidiary, agrees to continue to be responsive to customer inquiries regarding the adequacy of service, billing issues, and compliance issues, and to maintain customer access to compliance, billing, and other operational information.

23. Utilities, Inc., through the appropriate operating subsidiary, will continue to take steps designed to implement and further its commitment to provide superior service to North Carolina water and sewer customers.

The stipulation submitted by the Applicants and the North Topsail Intervenors settled the issues between them and requested that the transfer of the outstanding stock be approved immediately, subject to the following provisions and conditions:

1. Utilities Inc. and North Topsail Utilities, Inc. ("NTUI") have devised a three-phase plan to address capital improvements, capacity (measured in connections) and service issues for the system.

2. Phase I consisted of the restoration of the capacity to the system. Prior to Utilities Inc.'s purchase of the North Topsail sewer system, the North Carolina Division of Water Quality ("DWQ") reduced capacity available for construction of buildings from 877,000 gpd to 629,000 gpd.

3. Over the last six years, NTUI has conducted in-flow and infiltration studies, soil application rate studies, force main hydraulic studies and constructed additional facilities (at a cost of approximately $1.5 million) in its attempt to overcome the regulatory reductions in capacity.

NTUI has successfully restored the plant to its full capacity.

4. Phase II involves the current expansion of the plant. NTUI is in the process of expanding the plant by approximately one million gallons.

5. As of February 21, 2006, NTUI had a hydrogeologist on site. The hydrogeologist's work should be completed in approximately 30-45 days from February 21, 2006.

6. Upon completion of the hydrogeologist's work, NTUI's consulting engineer will develop plans for the expansion based on the hydrogeologist's report and will submit those plans to DWQ for approval and will request DWQ's "express review" procedure for these plans.

7. Assuming there are no permitting delays and that DWQ approves the plans in a timely manner, NTUI anticipates that construction on the plant expansion should be completed by mid-2007.

8. Phase III involves the future expansion of the plant and will follow the same process for developing additional capacity as Phase II. NTUI plans this future expansion of the plant to include an additional 1.5 million gallons. NTUI will use its best efforts to complete any additional hydrogeology work and consulting engineering plans necessary for Phase III by the end of 2007.

9. If the current real property owned by NTUI is insufficient to accommodate the Phase II and/or Phase III expansions discussed above, NTUI agrees to use such other means as necessary, reasonable, and prudent to satisfy these capacity expansion plans (including the acquisition of additional property so long as such acquisition is legally permissible and the cost is approved as reasonable and prudent by the Commission).

10. NTUI will make such other improvements or expansions to the mains as may be necessary to provide sufficient transport capacity of the waste stream from Topsail Island to the wastewater treatment facility in order to meet the demand for sewer services within the municipal corporate limits of the Town of North Topsail Beach.

11. A representative of NTUI will attend, if requested, at least quarterly meetings of the Town of North Topsail Beach Board of Alderman or a designated committee thereof to orally report on NTUI's efforts and progress consistent with the February 21, 2006, Stipulation and to answer questions about current and future sewer utility service in the Town.

12. Upon receipt of telephone or e-mail notice by local NTUI personnel in Onslow County from the Mayor or Town Manager of the Town of North Topsail Beach or their designee of odor problems from the pump station near the Highway 210 bridge, NTUI will take immediate action to evaluate the problem and take such action as it deems appropriate (which may include aeration and chemical/physical deodorizers).

13. Within ninety days following the final order approving the stock transfer in this docket, fecal and total coliform tests of the surface water at the pump station near the Highway 210 bridge will be conducted, at NTUI's expense, and the complete results of the tests will be provided to the Town Manager of the Town of North Topsail Beach.

14. The Town of North Topsail Beach, St. Moritz Homeowners Association, Inc. and Herschell E. Godwin, Jr. have agreed, subject to the stipulation set forth below, to withdraw their objections and to support the immediate granting of the transfer of the outstanding stock of Utilities, Inc. to Hydro Star. In addition, the Parties hereby stipulate as follows:

(a) NTUI shall have access to sufficient equity and debt capital to enable NTUI to adequately fund the above-referenced capital improvement plan, including the permitting thereof, and otherwise to meet the service needs of the NTUI customers at a reasonable cost.

(b) All plant expansions, land, and capital expenditures referenced above must be considered reasonable and prudent by the Commission. Additionally, Utilities Inc. and/or NTUI will be allowed to recover investor-financed investments through depreciation or amortization plus earn a reasonable rate of return on the undepreciated balance through its rate structure.

(c) By utilizing the standard of 120 gallons per bedroom, the expansion of NTUI should result in the following:

i. In Phase II, the expanded plant will have the treatment capacity of approximately 1,700,000 gpd. This translates to a system capacity of approximately 4,722 three-bedroom homes.
ii. Upon completion of Phase III, the expanded plant will have the treatment capacity of approximately 3,370,000 gpd. This translates to a system capacity of approximately 9,360 three-bedroom homes.

(d) NTUI shall continue to use a first-come, first-served, nondiscriminatory process for allocating capacity as it becomes available.

(e) All monthly reports to the Commission to be filed pursuant to Section "(u)" (paragraph 21 above of this order) of the Stipulation Between Applicants and Public Staff dated February 3, 2006 (hereinafter "Reports") will be provided monthly to the Town Manager of the Town of North Topsail Beach.

(f) NTUI will prepare and publish formal written procedures to implement the current first-come, first-served, nondiscriminatory process for allocating capacity as it becomes available (including the process for notification to those on the list who are eligible to receive capacity when it becomes available) and will include it as soon as practicable as part of one of the Reports. Any changes in the written procedures will be disclosed in subsequent Reports.

(g) By the end of the first full month after the final order of the Commission approving the stock transfer in this docket and every three months thereafter, NTUI will provide to the North Carolina Utilities Commission Public Staff, on a confidential basis and subject to appropriate non-disclosure protections, the list of customers, in priority order, who have requested and are waiting to receive sewer service from NTUI at the end of each quarter. This confidential list will be updated quarterly and will also indicate the previously listed customers who have received their allocated capacity since the previous quarter's report. NTUI will also make available publicly the list of all persons who have received their allocation of capacity during the previous quarter.

(h) NTUI will seek permission from the Commission as soon as practicable following the final order approving the stock transfer in this docket to take reserved capacity from individuals not ready to build and allocate it to those interests that are currently ready to build. The reserved capacity taken from the first party would then be substituted with a reservation for future capacity.

(i) If, for reasons beyond its control, NTUI cannot fulfill the obligations set forth in this Stipulation, it agrees to enter into good faith discussions and to cooperate with any other entity that would be able to provide the necessary infrastructure and capacity in order to satisfy the capacity projections set forth above (such alternatives may include, but are not limited to, the wholesale purchase of available bulk capacity).

On the basis of the application, the stipulations, the records of the Commission and the evidence of record, the Commission makes the following:

FINDINGS OF FACT

1. Utilities Inc. owns nine water and/or sewer operating subsidiaries in North Carolina subject to the Commission's jurisdiction. These are: Carolina Water Service Inc. of North Carolina; CWS Systems, Inc.; Transylvania Utilities, Inc.; Carolina Trace Utilities, Inc.; Elk River Utilities Inc.; North Topsail Utilities, Inc.; Carolina Pines Utilities, Inc.; Bradfield Farms Water Company; and Nero Utility Services, Inc. Utilities Inc. also owns the stock of Riverpointe Utility Corporation, Watauga Vista Water Corp., Belvedere Utility Company and Queens Harbor Utilities, Inc. that are separate corporations but that are treated as a part of Carolina Water Service Inc. of North Carolina for ratemaking purposes. These companies provide service to approximately 29,000 water customers and 20,000 wastewater customers in North Carolina. Utilities Inc. provides water and/or sewer service through approximately 90 operating companies in 17 states. The Utilities Inc. operating subsidiaries provide service to approximately 300,000 customers.

2. Hydro Star is a limited liability corporation duly organized and existing under the laws of the State of Delaware. Its principal office is located at 2929 Allen Parkway, Houston, Texas 77019. Hydro Star is a subsidiary of AIG Highstar Capital II, L.P. and certain of its affiliates (Highstar II). Highstar II is a group of private equity funds that invest primarily in energy infrastructure and related assets and businesses. Highstar II is sponsored by AIG Global Investment Group (AIGGIG). AIGGIG member companies are subsidiaries of American International Group, Inc. (AIG). AIGGIG comprises a group of international companies that provide investment advice and market asset management products and services to clients around the world.

3. Operating subsidiaries of Utilities Inc. serve approximately 29,000 water customers and 20,000 wastewater customers in North Carolina.

4. It is appropriate for Hydro Star to acquire the outstanding common stock of Utilities Inc. from Nuon Global Solutions, USA, BV according to the Stock Purchase Agreement submitted with the application in this docket.

5. Public witnesses expressed concerns about whether the proposed transfer would have an impact on quality of service issues. The concerns expressed by Corolla Light/Monteray Shores consumers have been addressed by the stipulation submitted by the Applicants and the Public Staff. The concerns expressed by the Carolina Trace and Fairfield Mountain customers were not addressed by any stipulation.

6. The stock acquisition will not require any additional terms, conditions, or requirements, and there will be no adverse rate impacts on retail customers.

7. The substitution of shareholders should not have a significant direct influence on the operations of the North Carolina subsidiaries of Utilities, Inc., and the current level of service will be maintained.

8. The transfer of the stock in Utilities Inc. to Hydro Star is justified by the public convenience and necessity.

9. The stipulations between the Applicants and the Public Staff and between the Applicants and the Town of North Topsail Beach and other North Topsail Intervenors submitted in this docket should be approved.

10. NTUI has stand-alone rates for the North Topsail franchise area, which are not included in the uniform rate structure of any of Utilities, Inc.'s other North Carolina Commission regulated subsidiaries.

EVIDENCE AND CONCLUSIONS ON CUSTOMER TESTIMONY

Public witnesses Hugh McCain and Robert Wemyss from Monteray Shores, and James Alexy from Corolla Light testified as to their concerns about the water quality and supply, particularly the elevated trihalomethane levels, the level of chlorides which these customers stated makes the water undrinkable and damages plumbing fixtures, low water pressure, and what these customers believed to be diminishing well supply, particularly at Corolla Light.

Vincent Roy and Stewart L. Aiken testified on behalf of various property owners associations at Carolina Trace regarding a number of service issues. The primary issues they discussed were: the need for expansion of the wastewater treatment plant, the condition of the sewer service lines, mains, manholes which they believed resulted in periodic backups, overflows, and the need for increased inspections and remedial actions, the possible replacement of a water main on Turnbury Street which had had three water main breaks in eighteen months, the request to bore under roads when installing water service lines and the condition of the roads as a result of road cuts for the installation and repairs of the water mains and services.

John Rutherford testified on behalf of the Fairfield Mountains Property Owners Association. His primary concerns were that the Fairfield Mountains Property Owners Association should not be required to provide well lots for water system expansions outside of Fairfield Mountains, and the number of main breaks and resulting leaks.

Charles Lubrecht testified on behalf of Magnolia Plantation Partnership, a developer at Carolina Pines subdivision. He testified that Magnolia Plantation Partnership withdrew its intervention in this proceeding upon reaching a clarification agreement with Carolina Pines Utilities, Inc., a subsidiary of Utilities, Inc., as to the wastewater capacity contracted to Magnolia Plantation Partnership, as evidenced by Lubrecht Exhibit 1.

The Commission concludes that the Commission will monitor the service issues about which the customers testified through the reports to be filed by Utilities, Inc., or its respective subsidiaries, and take appropriate action as needed based on those reports.

The stipulation between the Public Staff and Utilities, Inc. and Hydro Star in paragraph 20 and ordering paragraph 1(t), of this Order requires monthly reports for Corolla Light/Monteray Shores until the Commission concludes that the filing of the reports is no longer necessary. The Commission will order that Utilities, Inc., through its appropriate subsidiary should file with the Commission within 30 days of the date of this order, comprehensive reports on the service issues raised by the customers from Carolina Trace and Fairfield Mountains as well.

CONCLUSIONS

Based upon the foregoing, the Commission is of the opinion that the request that Hydro Star acquire the stock of Utilities Inc. is in the public interest and is approved, and that the stipulation between the Applicants and the Public Staff and between the Applicants and the Town of North Topsail Beach and other North Topsail Intervenors should be approved.

The stipulation filed February 21, 2006, between the Town of North Topsail Beach, the North Topsail Intervenors and Applicants shall be applicable only to the North Topsail franchise area, including future expansions. Stipulation paragraph 15(b)(ordering paragraph 1gg) shall remain operable only so long as NTUI retains stand-alone rates and the North Topsail franchise service area does not become part of the uniform rate structure of any of Utilities, Inc.'s other North Carolina Commission regulated subsidiaries. Stipulation paragraph 15(b) (ordering paragraph gg), shall have no precedential value for any of the service areas of Utilities, Inc.'s other North Carolina Commission regulated subsidiaries.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for transfer of the stock of Utilities Inc. to Hydro Star as described herein and in the application is approved upon the following conditions, and that Utilities Inc. and Hydro Star are ordered to comply with such conditions:

(a) All records of Utilities, Inc. will be physically available as required by North Carolina law.

(b) Hydro Star will comply with any Commission requirement that Utilities, Inc. personnel familiar with the company records be reasonably available in North Carolina.

(c) The Applicants will not seek recovery of losses or subsidization of non-utility subsidiaries of Hydro Star or Utilities, Inc. from North Carolina customers.

(d) The officers and management of Utilities, Inc. will have reasonable authority to commit Utilities, Inc., and its North Carolina regulated subsidiaries, on matters considered jurisdictional to the Commission.

(e) The Applicants will seek Commission permission before a corporate restructuring of Utilities, Inc.

(f) No franchise of Utilities, Inc., or any of its North Carolina regulated subsidiaries, now existing or hereafter issued by the Commission under the provisions of the Public Utilities Act of North Carolina, shall be sold, assigned, pledged or transferred, nor shall control thereof be changed through stock transfer or otherwise, or any rights thereunder leased, nor shall any merger or combination including Hydro Star and/or Utilities, Inc. affecting Utilities, Inc. and/or any of its North Carolina regulated subsidiaries, be made through acquisition of control by stock purchase or otherwise, except after application to and written approval by the Commission.

(g) Hydro Star and Utilities, Inc. agree to be bound by North Carolina law and Commission Orders and rules and regulations as they relate to Utilities, Inc.'s North Carolina regulated subsidiaries.

(h) All costs of the acquisition incurred by Hydro Star and/or Utilities, Inc., including compensation costs, and all direct and indirect corporate cost increases for Utilities, Inc. or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of Utilities, Inc.'s subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that Utilities, Inc. would have incurred using prudent business judgment had the acquisition not occurred.

(i) All costs of the 2002 merger approved by the Commission in Docket No. W-1000, Sub 9, incurred by nv Nuon and/or Utilities, Inc., including compensation costs, and all direct and indirect corporate cost increases for Utilities, Inc. or any of its subsidiaries will be recorded to account number 426 (Miscellaneous Non Utility Expense) and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of Utilities, Inc.'s subsidiaries. For purposes of this agreement, the term "corporate cost increases" is defined as costs in excess of the level that Utilities, Inc., would have incurred using prudent business judgment had the merger not occurred.

(j) Future payments to officers for annual bonuses, incentive bonuses, long term incentive bonuses, and any other bonuses made in relation to the acquisition will be excluded from Utilities, Inc.'s utility accounts and shall be treated for accounting and ratemaking purposes so that they do not affect the water and sewer rates and charges of Utilities, Inc.'s subsidiaries.

(k) Base salaries, compensation payments, annual bonuses, incentive bonuses, long term incentive bonuses, any other bonuses, and any incentive compensation other than those listed in Item (j) above shall be subject to review and ratemaking adjustment in future rate proceedings for Utilities, Inc., where Utilities, Inc. holds a Commission-issued certificate, and for its North Carolina regulated subsidiaries (including areas included within the certificate of such subsidiaries through operation of G.S. 62-110(a)). The burden of proof on each of these issues shall be upon Utilities, Inc., and its North Carolina regulated subsidiaries.

(l) Any acquisition adjustment that results from the acquisition will be excluded from Utilities, Inc.'s utility accounts and treated for accounting and ratemaking purposes so that it does not affect water and sewer rates and charges of Utilities, Inc.'s subsidiaries.

(m) Utilities, Inc. and each of its North Carolina regulated subsidiaries shall maintain its books and records so that its equity capital is recorded pursuant to the respective NARUC Uniform System of Accounts for Class A Water and Class A Wastewater Utilities, as revised in 1996, and all subsequent revisions.

(n) Applicants shall provide Utilities, Inc., to the extent it holds certificates issued by the Commission, and its North Carolina regulated subsidiaries with sufficient access to equity and debt capital to enable Utilities, Inc. and its North Carolina regulated subsidiaries to adequately fund and maintain their current and future water and wastewater systems, and otherwise meet the service needs of their customers at a reasonable cost. The timing and quantity of any capital expenditures or discrete capital infusion shall be determined by the Applicants' best judgment consistent with the requirement to maintain the current and future water and wastewater systems and otherwise meet the service needs of the customers at a reasonable cost.

(o) The Applicants agree to file all proposed amendments, updates, and new contracts pertaining to affiliated transactions with the Commission and get approval for the North Carolina operating subsidiary to pay compensation to an affiliate in advance of effectiveness as required under North Carolina General Statute 62-153.

(p) The Applicants and all affiliates shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases and/or any other adverse effects of the transfer.

(q) The books and records of Hydro Star and any other affiliated companies will be made available for inspection as required under North Carolina General Statute 62-51.

(r) Utilities, Inc.'s North Carolina operating subsidiaries and Utilities, Inc., where it holds certificates from the Commission, shall comply with the requirements of G.S. 62-153 with respect to the procurement of goods or services from Hydro Star or other affiliated or subsidiary companies or entities. Whenever Utilities, Inc.'s North Carolina operating subsidiaries and Utilities, Inc., where it holds certificates from the Commission, seeks to recover through rates the costs of goods or services procured from Hydro Star or other affiliated or subsidiary companies or entities, or whenever the Commission requires it, Utilities, Inc., shall have the burden of persuasion and proof as to the reasonableness of such costs in accordance with North Carolina law.

(s) Utilities, Inc.'s operations in North Carolina are generally in compliance with applicable environmental regulations. In cases where Utilities Inc.'s affiliates are involved in environmental compliance issues, Utilities, Inc. and Hydro Star agree to continue to cooperate with all regulatory agencies in addressing any outstanding compliance issues, to the satisfaction of the environmental regulatory agencies and the Public Staff.

(t) Utilities, Inc., through the appropriate operating subsidiary, shall use its best reasonable efforts to resolve the customer service complaints filed in the Commission's official file in this docket as of the close of the hearing or presented at the hearing from Corolla Light/Monteray Shores consumers in regard to water supply and chloride and trihalomethane levels. Utilities, Inc. shall file monthly progress reports with the Commission addressing water supply and chloride and elevated trihalomethane levels until such time that the Commission orders that filing the reports is no longer necessary. The first report shall be filed within 30 days from the date of this order.

(u) Utilities, Inc., through the appropriate operating subsidiary, shall use its best reasonable efforts to address the wastewater capacity and expansion complaints filed in the Commission's official file in this docket as of the close of the hearing or presented at the hearing from North Topsail Beach consumers. Utilities, Inc. shall file with the Commission monthly progress reports addressing wastewater capacity and expansion until such time that the Commission orders that filing the reports is no longer necessary. The first report shall be filed within 30 days of the date Applicants provide the Commission notice of the closing of the acquisition.

(v) Utilities, Inc., through the appropriate operating subsidiary, agrees to continue to be responsive to customer inquiries regarding the adequacy of service, billing issues, and compliance issues, and to maintain customer access to compliance, billing, and other operational information.

(w) Utilities, Inc., through the appropriate operating subsidiary, will continue to take steps designed to implement and further its commitment to provide superior service to North Carolina water and sewer customers.

(x) Upon completion of the hydrogeologist's work on Phase II of NTUI's current expansion plan for the North Topsail sewer system, NTUI's consulting engineer will develop plans for the expansion based on the hydrogeologist's report and will submit those plans to DWQ for approval and will request DWQ's "express review" procedure for these plans.

(y) Assuming there are no permitting delays and that DWQ approves the plans in a timely manner, NTUI anticipates that construction on the plant expansion should be completed by mid-2007.

(z) Phase III involves the future expansion of the plant and will follow the same process for developing additional capacity as Phase II. NTUI plans this future expansion of the plant to include an additional 1.5 million gallons. NTUI will use its best efforts to complete any additional hydrogeology work and consulting engineering plans necessary for Phase III by the end of 2007.

(aa) If the current real property owned by NTUI is insufficient to accommodate the Phase II and/or Phase III expansions discussed above, NTUI shall use such other means as necessary, reasonable, and prudent to satisfy these capacity expansions plans (including the acquisition of additional property so long as such acquisition is legally permissible and the cost is approved as reasonable and prudent by the Commission).

(bb) NTUI will make such other improvements or expansions to the mains as may be necessary to provide sufficient transport capacity of the waste stream from Topsail Island to the wastewater treatment facility in order to meet the demand for sewer services within the municipal corporate limits of the Town of North Topsail Beach.

(cc) A representative of NTUI will attend, if requested, at least quarterly meetings of the Town of North Topsail Beach Board of Alderman or a designated committee thereof to orally report on NTUI's efforts and progress consistent with the Stipulation entered into between Applicants and the Town of North Topsail Beach and to answer questions about current and future sewer utility service in the Town of North Topsail Beach.

(dd) Upon receipt of telephone or e-mail notice by local NTUI personnel in Onslow County from the Mayor or Town Manager of the Town of North Topsail Beach or their designee of odor problems from the pump station near the Highway 210 bridge, NTUI will take immediate action to evaluate the problem and take such action as it deems appropriate (which may include aeration and chemical/physical deodorizers).

(ee) Within ninety days following the final order approving the stock transfer, fecal and total coliform tests of the surface water at the pump station near the Highway 210 bridge will be conducted, at NTUI's expense, and the complete results of the tests will be provided to the Town Manager of the Town of North Topsail Beach.

(ff) NTUI shall have access to sufficient equity and debt capital to enable NTUI to adequately fund the above-referenced capital improvement plan, including the permitting thereof, and otherwise to meet the service needs of the NTUI customers at a reasonable cost.

(gg) All plant expansions, land, and capital expenditures referenced above must be considered reasonable and prudent by the Commission. Additionally, Utilities Inc. and/or NTUI will be allowed to recover investor-financed investments through depreciation or amortization plus earn a reasonable rate of return on the undepreciated balance through its rate structure.

(hh) By utilizing the standard of 120 gallons per bedroom, the expansion of NTUI should result in the following:

i. In Phase II, the expanded plant will have the treatment capacity of approximately 1,700,000 gpd. This translates to a system capacity of approximately 4,722 three-bedroom homes.

ii. Upon completion of Phase III, the expanded plant will have the treatment capacity of approximately 3,370,000 gpd. This translates to a system capacity of approximately 9,360 three-bedroom homes.

(ii) NTUI shall continue to use a first-come, first-served, nondiscriminatory process for allocating capacity as it becomes available.

(jj) All monthly reports to the Commission to be filed pursuant to Section "(u)" of the Stipulation Between Applicants and Public Staff dated February 3, 2006 (hereinafter "Reports") will be provided monthly to the Town Manager of the Town of North Topsail Beach.

(kk) NTUI will prepare and publish formal written procedures to implement the current first-come, first-served, nondiscriminatory process for allocating capacity as it becomes available (including the process for notification to those on the list who are eligible to receive capacity when it becomes available) and will include it as soon as practicable as part of one of the Reports. Any changes in the written procedures will be disclosed in subsequent Reports.

(ll) By the end of the first full month after the final order of the Commission approving the stock transfer and every three months thereafter, NTUI will provide to the North Carolina Utilities Commission Public Staff, on a confidential basis and subject to appropriate non-disclosure protections, the list of customers, in priority order, who have requested and are waiting to receive sewer service from NTUI at the end of each quarter. This confidential list will be updated quarterly and will also indicate the previously listed customers who have received their allocated capacity since the previous quarter's report. NTUI will also make available publicly the list of all persons who have received their allocation of capacity during the previous quarter.

(mm) NTUI will seek permission from the Commission as soon as practicable following the final order approving the stock transfer to take reserved capacity from individuals not ready to build and allocate it to those interests that are currently ready to build. The reserved capacity taken from the first party would then be substituted with a reservation for future capacity.

(nn) If, for reasons beyond its control, NTUI cannot fulfill the obligations set forth in this Stipulation, it agrees to enter into good faith discussions and to cooperate with any other entity that would be able to provide the necessary infrastructure and capacity in order to satisfy the capacity projections set forth above (such alternatives may include, but are not limited to, the wholesale purchase of available bulk capacity).

2. That the Joint Stipulation of the Applicants and the Public Staff signed and filed with the Commission on February 3, 2006, is hereby approved.

3. That the Joint Stipulation of the Applicants and the Town of North Topsail Beach and the other North Topsail Intervenors signed and filed with the Commission on February 21, 2006, is hereby approved.

4. That the stipulation between the Town of North Topsail Beach, the North Topsail Intervenors and the Applicants shall be applicable only to the North Topsail franchise area, including future expansions. Stipulation paragraph 15(b), which is ordering paragraph 1(gg), shall remain operable only so long as North Topsail Utilities retains stand-alone rates and the North Topsail franchise service area does not become part of the uniform rate structure of any of Utilities, Inc.'s other North Carolina regulated subsidiaries. Stipulation paragraph 15(b) (ordering paragraph 1(gg), shall have no precedential value for any of the service areas of Utilities, Inc.'s other North Carolina Commission regulated subsidiaries.

5. That, the Commission is particularly troubled by the concerns brought to our attention by the Carolina Trace, Fairfield Mountains and Corolla Light/Monteray Shores communities (as well as those brought to our attention by intervenors who have subsequently withdrawn their petitions after extended negotiations with the Applicants). To address these concerns, we require the Applicants to do the following:

A. Carolina Trace

1. That Applicants shall file a comprehensive report including planned actions within 30 days of this order addressing the concerns identified by the Carolina Trace customers in this proceeding. The comprehensive report shall include at a minimum the following:

a. The efforts undertaken by Utilities, Inc. or the appropriate subsidiary to locate and/or map any and all sewer lines and mains in the Carolina Trace service areas.
b. An update on the status of wastewater treatment in the service area including a detailed explanation of the capacity of current plants, the necessity for expansion of the treatment plant in the foreseeable future, and actions being taken to meet the wastewater treatment needs of current customers.
c. A timetable for completing the location and mapping of existing sewer lines and mains serving Carolina Trace.
d. Methods which can be utilized to repair breaks in service lines which will minimize road cuts. This report shall include the costs of acquisition of technology which will minimize road repairs and the potential effect, if any, on the rates of customers.
e. A detailed report on the current inspection program that Utilities, Inc. or the appropriate subsidiary is employing in the absence of complete maps for its service lines.
f. Any other concerns raised by the Carolina Trace customers in the hearing on this matter.

B. Fairfield Mountains

1. That Applicants shall file a comprehensive report within 30 days of this order addressing the concerns of the Fairfield Mountains public witnesses. The comprehensive report shall include at a minimum the following:

a. A statement of Utilities, Inc. or the appropriate subsidiary's position as to whether it is required to provide fire protection services to Fairfield Mountains.
b. To the extent that information is non-proprietary, copies of documents including bankruptcy documents, contracts and maps of its service territories which explain the rights, duties and obligations of Utilities, Inc. or the appropriate subsidiary to provide utility service to Fairfield Mountains. To the extent that the documents listed above are deemed proprietary by the company, those documents shall be filed under seal pending review by the Commission to determine if the documents shall be released.
c. To the extent that the information is non-proprietary, plans for expansion or service in areas contiguous to Fairfield Mountains which may necessitate transfer of water from wells located in Fairfield Mountains to the contiguous areas. To the extent that the documents listed above are deemed proprietary by the company, those documents shall be filed under seal pending review by the Commission to determine if the documents shall be released.
d. Any other concerns that were raised by the Fairfield Mountains customers in the hearing on this matter.

C. Corolla Light/Monteray Shores

1. That Applicants shall file a comprehensive report within 30 days of this order addressing the concerns of the Corolla Light/Monteray Shores consumers, which report shall include at a minimum the following:

a. A statement of Utilities, Inc. or the appropriate subsidiary of what actions, if any, it has previously taken to lower the chloride levels and trihalomethane levels in the water supply.
b. A statement of Utilities, Inc. or the appropriate subsidiary of what actions, if any, it intends to take in the future to lower the chloride levels and the trihalomethane levels in the water supply.
c. The position of Utilities, Inc. or its appropriate subsidiary as to the complaints pertaining to lack of water pressure and what steps, if any, it has previously taken or intends to take in the future to resolve any deficiencies regarding same.

Each of the aforementioned reports required in sections A, B, and C of this paragraph shall be filed contemporaneously with the Public Staff and the Commission until further notice by the Commission. Within thirty days of receiving said reports, the Public Staff shall file comments addressing each item included within the report.

The Commission intends to vigorously monitor the Applicants' compliance with these requirements and shall retain jurisdiction to reopen these issues for further review and remediation should the need arise in the future.

6. That Utilities, Inc. shall file with the Commission a pre-closing and post-closing balance sheet and any journal entries made to record the stock transfer and any related transactions within ninety days of closing.

7. That Utilities, Inc. shall provide written notification to the Commission within 10 days after the transfer has been completed.

8. That the Notice to Customers, attached as Appendix A, shall be mailed with sufficient postage to all customers of the Utilities Inc. North Carolina operating subsidiaries within 15 days of the date of this Order, and that Applicants shall submit to the Commission the attached Certificate of Service properly signed and notarized not later than five days.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of April, 2006.

North Carolina Utilities Commission
Gail L. Mount, Deputy Clerk

Lh032706.01

APPENDIX A

DOCKET NO. W-1000, SUB 11

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Hydro Star, LLC	)	NOTICE TO CUSTOMERS
to Acquire the Outstanding	)	OF TRANSFER
Stock of Utilities, Inc.	)	

BY THE COMMISSION: Notice is given that the North Carolina Utilities Commission has approved the application of Hydro Star, LLC to acquire the outstanding stock of Utilities, Inc. pursuant to a Stock Purchase Agreement between Hydro Star, LLC and Nuon Global Solutions USA, BV. Utilities, Inc. owns nine water and/or sewer operating subsidiaries in North Carolina subject to the Commission's jurisdiction. These are: Carolina Water Service Inc. of North Carolina; CWS Systems, Inc.; Transylvania Utilities, Inc.; Carolina Trace Utilities, Inc.: Elk River Utilities, Inc.; North Topsail Utilities, Inc.; Carolina Pines Utilities, Inc.; Bradfield Farms Water Company; and Nero Utility Services, Inc.

During the hearing, witnesses presented testimony that highlighted service issues in the communities of North Topsail Beach, Carolina Trace, Fairfield Mountains and Corolla Light/Monteray Shores. The Commission has imposed on the Applicants reporting and monitoring requirements to address these quality of service issues.

There is no change in the current rates associated with this transfer. There is no change in the mailing address or telephone number of the utility companies. Should there be any future changes in telephone numbers or mailing addresses, customers will be notified.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of April, 2006.

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-1000, Sub 11, and the Notice was mailed or hand delivered by the date specified in the Order.

This the ________ day of ______________, ______.

By: ____________________________
Signature

____
Name of Utility Company

WATER AND SEWER – SALE/TRANSFER

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 ____________________, Docket No. W-1000, Sub 11.

Witness my hand and notarial seal, this the ______ day of ______________, ________.

____
Notary Public

____
Address

____
Date

My Commission Expires:
(SEAL)

ORDERS AND DECISIONS – PRINTED

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ORDERS AND DECISIONS -- PRINTED

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Progress Energy Carolinas, Inc.; Carolina Power & Light Company, d/b/a -- E-2,
SUB 834; Order on Annual Reporting Requirements (05/04/06)
SUB 881; Order Granting Authority to Issue/Sell Additional Securities (Long-Term Debt and/or Preferred Stock) (01/31/2006)

<u>ELECTRIC – Merger</u>
Duke Energy Carolinas, LLC -- E-7,
SUB 795; Order Accepting Agreement for Filing and Allowing Operation Under Agreement Effective Upon Closing of Merger (3/31/2006)
SUB 795B; Order Approving Proposed Auditor (11/09/2006)

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ELECTRIC - Rate Schedules/Riders/Service Rules and Regulations

Duke Energy Carolinas, LLC -- E-7,

SUB 784; E-7, SUB 811; Order Approving Modifications (07/26/2006)

SUB 811; Order Modifying Tariffs (04/05/2006)

SUB 812; Order Approving Underground Service Installation Pilot (04/20/2006)

SUB 822; - Order Approving Revised Service Regulations (12/20/2006)

Progress Energy Carolinas, Inc.; Carolina Power & Light Company, d/b/a -- E-2,

SUB 681; E-2, SUB 819 – Order Approving Revisions (12/14/2006); Errata Order (12/19/2006)

SUB 893; Order Allowing Rider to Become Effective (09/29/2006

SUB 895; Order Approving Revised Schedule (12/20/2006)

SUB 887; Order Revising Rate Schedule (03/07/2006); Errata Order (03/09/2006)

ELECTRIC - Sale/Transfer

Duke Energy Carolinas, LLC – E-7;

SUB 816; EMP-1, SUB 1; Order Approv. Transfer of Certificate and Facility Issuing Certif. Subject to Conditions (07/25/2006); Order Adopt. Additional Condition (11/20/2006)

ELECTRIC – Securities

Duke Energy Carolinas, LLC -- E-7,

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SUB 750; Order Authorizing Amendment of Revolving Credit Facility to Extend Maturity Date (06/28/2006)

ELECTRIC MERCHANT PLANT

ELECTRIC MERCHANT PLANT - Electric Generation Certificate

Industrial Power Generating Company, LLC -- EMP-14, SUB 0; Order Granting Certificate (11/06/2006)

ELECTRIC MERCHANT PLANT - Sale/Transfer

Progress Energy Ventures, Inc. -- EMP-5, SUB 2; EMP-13, SUB 0; Order Approving Transfer and Issuing Certificate Subject to Conditions (08/17/2006)

ELECTRIC SUPPLIER

ELECTRIC SUPPLIER - Reassignment of Service Area/Exchange

Duke Power/Energy United Electric Membership Corporation -- ES-113, SUB 0; Order Approving Assignment of Service Areas (03/22/2006)

Wake Electric Membership Corp./Town of Louisburg -- ES-114, SUB 0; Order Approving Agreement of Electric Suppliers (06/29/2006)

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HOUSING/HOSPITAL

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Housing Authority – Surry County -- H-69, SUB 0; Order Granting Certificate and Canceling Hearing (02/07/2006)

NATURAL GAS

NATURAL GAS – Accounting

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 530; Order Approving Deferral Accounting (10/27/2006)
SUB 531; Order Approving Accounting Adjustment (10/27/2006)

NATURAL GAS - Adjustments of Rates/Charges

Cardinal Extension Company, LLC -- G-39,
SUB 9; Order Approving Adjustment to Fuel Retention Percentage (03/22/2006)
Frontier Energy, LLC -- G-40,
SUB 63; Order Allowing Rate Changes Effective April 1, 2006 (03/30/2006)
SUB 64; Order Allowing Rate Changes Effective August 1, 2006 (07/26/2006)
SUB 65; Order Allowing Rate Changes Effective November 1, 2006 (11/02/2006)
Municipal Gas Authority of Georgia/City of Toccoa, Georgia – G-41,
SUB 18; Recommended Order on Annual Review of Gas Costs (01/10/2006)
Piedmont Natural Gas Company, Inc. -- G-9,
SUB 507; G-21, SUB 465; Order on Annual Review of Gas Costs (04/04/2006)
SUB 516; Order Allowing Rate Changes Effective February 1, 2006 (01/30/2006)
SUB 518; Order Allowing Rate Changes Effective March 1, 2006 (03/01/2006)
SUB 523; Order Allowing Rate Changes Effective May 1, 2006 (05/04/2006)
SUB 533; Order Allowing Rate Adjustments Effective November 1, 2006 (11/02/2006)
Public Service Company of N.C., Inc. -- G-5,
SUB 476; Order Allowing Rate Changes Effective on January 1, 2006 (01/06/2006)
SUB 477; Order Allowing Rate Changes Effective February 1, 2006 (01/30/2006)
SUB 479; Order Allowing Rate Changes Effective March 1, 2006 (03/01/2006)

NATURAL GAS – Certificate

Bloomsbury, LLC -- G-50, SUB 0; Order Approving Master Metering (08/11/2006)

NATURAL GAS – Complaint

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 525; Order Dismissing Complaint and Closing Docket (07/20/2006)
SUB 534; Order Dismissing Complaint and Closing Docket (12/11/2006)
Public Service Company of N.C., Inc. -- G-5,
SUB 463; Order Dismissing Complaint and Closing Docket (02/01/2006)
SUB 482; Order on Annual Review of Gas Costs (09/28/2006)

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NATURAL GAS - Contracts/Agreements

Piedmont Natural Gas Company, Inc. -- G-9;
SUB 514; Order Approving Agreement (05/04/2006)
SUB 517; Order Approving Agreement (02/23/2006)

Public Service Company of N.C., Inc. -- G-5, SUB 475; Order Accepting Agreement for Filing and Allowing Utility to Pay Compensation (04/28/2006)

NATURAL GAS - Filings Due per Order or Rule

Frontier Energy, LLC -- G-40, SUB 27; Order Approving Revised Financing Plan and AFUDC Rate, Accepting Affiliated Contracts for Filing and Permitting Operation Pursuant to G.S. 62-153 (11/30/2006)

Public Service Company of N.C., Inc. -- G-5,
SUB 310; Order Discontinuing Reporting Requirement and Closing Docket (12/20/2006)
SUB 438; Order Approving Modifications (05/05/2006)

NATURAL GAS – Miscellaneous

Municipal Gas Authority of Georgia/City of Toccoa, Georgia -- G-41, SUB 21; Order on Annual Review of Gas Costs (12/22/2006)

Public Service Company of N.C., Inc. -- G-5,
SUB 474; Order Approving Deferred Accounting (01/11/2006)
SUB 478; Order Authorizing the Deposit of Supplier Refunds into the Deferred Accounts (03/14/2006)

Trademark Condominium -- G-48, SUB 0; Order Approving Metering Plan (06/01/2006)

NATURAL GAS - Rate Increase

Piedmont Natural Gas Company, Inc. -- G-9, SUB 499; Order Approving Conservation Program Modifications (06/29/2006); Errata Order (07/03/2006)

NATURAL GAS - Rate Schedules/Riders/Service Rules and Regulations

Piedmont Natural Gas Company, Inc. -- G-9, SUB 515; Order Allowing Rate Changes Effective on January 1, 2006 (01/06/2006)

NATURAL GAS – Reports

Frontier Energy, LLC - G-40, SUB 60; Order on Annual Review of Gas Costs (05/02/2006); Order Approving Modifications (12/14/2006)

NATURAL GAS – Securities

Piedmont Natural Gas Company, Inc. -- G-9,
SUB 522; Order Granting Authority to Borrow Under Credit Agreement (04/25/2006)
SUB 526; Piedmont Natural Gas Company, Inc. - Order Granting Authority to Issue Shares of Stock (07/26/2006)

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SPECIAL CERTIFICATE/PSP – Certificates Issued

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ATN, Inc., d/b/a AmTel Networks Inc.	SC-1791, SUB 0	(07/26/2006)
Empire Payphones, Inc.	SC-1789, SUB 0	(03/21/2006)
Grayson Henson, d/b/a IFIXIT	SC-1786, SUB 0	(01/30/2006)
H.Q. Entertainment Services, Inc.	SC-1787, SUB 0	(02/03/2006)
Laura Bell	SC-1792, SUB 0	(08/03/2006)
Sherry L. Faw, d/b/a Southeastern Poolphone Service	SC-1790, SUB 0	(05/22/2006)
Wil Huang and Harout Boghossian, d/b/a HQ Payphone Services	SC-1788, SUB 0	(02/21/2006)

SPECIAL CERTIFICATE/PSP – Certificates Canceled

Company	Docket No.	Date
Alexander, Willie J., d/b/a Professional Counseling and Consultation Serv.	SC-1762, SUB 1	(10/10/2006)
Commercial Oil Company	SC-248, SUB 1	(10/26/2006)
Dubois, Charles, d/b/a Poplar Grove Mini Mart	SC-1521, SUB 3	(05/22/2006)
Food N' Fun, Inc.	SC-1719, SUB 1	(03/10/2006)
Franklin Inns, Inc.	SC-1398, SUB 1	(05/09/2006)
Gosnell, E. M.	SC-1680, SUB 1	(05/09/2006)
Grayson Henson, d/b/a IFIXIT	SC-1786, SUB 1	(09/12/2006)
H.Q. Entertainment Services, Inc.	SC-1787, SUB 1	(09/27/2006)
Moffit, Renee	SC-1724, SUB 1	(10/26/2006)
Northside Bowling Lanes, Inc.	SC-295, SUB 2	(10/25/2006)
Park, Kyung O.	SC-1679, SUB 1	(12/11/2006)
Schmidt, Robert P.	SC-1694, SUB 1	(01/30/2006)
Short Enterprises, Inc.	SC-1283, SUB 1	(10/26/2006)
Smith, Dalphine A.	SC-1738, SUB 1	(07/26/2006)
Weil, Melody C., d/b/a Combined Public Communications	SC-1741, SUB 1	(05/09/2006)

Jackson, Marvin – SC-1000, SUB 12; SC-1723, SUB 2; Order Affirming Previous Commission Order Canceling Certificate (06/14/2006)

Neel, Daniel B., d/b/a Wired Communications – SC-1000, SUB 12; SC-1614, SUB 4; Order Affirming Previous Commission Order Canceling Certificate (06/08/2006)

Super Service Southwest, Inc. – SC-1000, SUB 12; SC-1079, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (06/14/2006)

SPECIAL CERTIFICATE/PSP – Miscellaneous

Dairy Fresh, Inc. -- SC-833, SUB 1; Order Reissuing Certificate Due to Address Change (04/24/2006)

International Payphone Corporation -- SC-1688, SUB 1; Order Reissuing Special Certificate Due to Address Change (09/12/2006)

Southeast Communications, Inc. -- SC-1397, SUB 1; Order Reissuing Special Certificate Due to Address Change (07/21/2006)

Embarq Payphone Services, Inc. -- SC-1474, SUB 5; Order Reissuing Special Certificate Due to Name Change (05/02/2006)

Windstream North Carolina, Inc. -- SC-1369, SUB 1; Order Issuing Special Certificate Due to Name and Address Change (09/18/2006)

SMALL POWER PRODUCER

SMALL POWER PRODUCER – Certificate

SMALL POWER PRODUCER – Certificates Issued

Company	Docket No.	Date
Boniske, H. M.	SP-166, SUB 0	(08/30/2006)
Carolina Solar Energy LLC	SP-159, SUB 0	(08/30/2006)
Carolina Solar Energy LLC	SP-159, SUB 1	(08/30/2006)
Currens, John	SP-168, SUB 0	(08/30/2006)
Enerdyne Properties, LLC	SP-154, SUB 0	(02/23/2006)
Green Path Enterprises, LLC	SP-174, SUB 0	(11/09/2006)
Heddaeus, Mark	SP-177, SUB 0	(11/09/2006)
Holzworth Holdings, Inc.	SP-173, SUB 0	(10/27/2006)
Jafasa Farms	SP-170, SUB 0	(10/20/2006)
Jafasa Farms	SP-170, SUB 1	(10/20/2006)
Matthews, Byron	SP-172, SUB 0	(11/09/2006)
Poteat, William O.	SP-178, SUB 0	(11/22/2006)
Methane Credit, LLC	SP-157, SUB 0	(05/24/2006)
Neumann, Ronald	SP-164, SUB 0	(07/26/2006)
Parre, Khlaire	SP-156, SUB 0	(03/01/2006)
Reily Recovery Systems, Inc.	SP-184, SUB 0	(12/14/2006)
Senior, Christopher D.	SP-175, SUB 0	(11/02/2006)
Sesalie Smathers & Jason Sprouse	SP-171, SUB 0	(10/19/2006)
Sherman, James B.	SP-182, SUB 0	(12/14/2006)
Slome, Shawn Lex	SP-169, SUB 0	(09/21/2006)
Stanford; David Birkhead & Kathy	SP-180, SUB 0	(11/30/2006)
Steven Mark McCraw	SP-179, SUB 0	(11/22/2006)
Thomas; David M.	SP-181, SUB 0	(11/30/2006)
Thomason; Robert D.	SP-176, SUB 0	(11/02/2006)
Thomason, Stephen Andrew	SP-183, SUB 0	(12/14/2006)

Altamahaw Hydro, LLC -- SP-160, SUB 0; Order Approving Transfer of Certificate (06/14/2006)

Hayden Harman Foundation -- SP-155, SUB 0; Order Correcting Clerical Errors and Issuing Corrected Certificate (01/27/2006)

Matthews, Byron -- SP-172, SUB 0; Errata Order Reissuing Certificate (12/11/2006)

SMALL POWER PRODUCER – Sale/Transfer

Brushy Mountain Power Company; Neisler, Inc., d/b/a – SP-33, SUB 1; SP-162, SUB 0; Order Approving Transfer (05/24/2006)

Cogentrix of NC, Inc. – SP-16,
- SUB 9; SP-158, SUB 0; Order Approving Transfer (03/17/2006)
- SUB 10; SP-16, SUB 11; SP-165, SUB 0; SP-165, SUB 1; Order Approving Transfer (08/08/2006)
- SUB 10; SP-16, SUB 11; SP-165, SUB 0; SP-165, SUB 1; Order Re-Issuing Certificates (08/14/2006)

Green Power Energy Holdings, LLC – SP-138, SUB 1; SP-161, SUB 0; Order Approving Transfer (05/24/2006)

TELECOMMUNICATIONS

TELECOMMUNICATIONS - Certificate

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Company	Docket No.	Date
Airespring, Inc.	P-1265, SUB 1	(06/28/2006)
AmeriVon, LLC	P-1386, SUB 0	(02/03/2006)
BLC Management, LLC, d/b/a Angles Communication Solutions LLC	P-1415, SUB 0	(09/27/2006)
BLC Management, LLC, d/b/a Angles Communication Solutions LLC	P-1415, SUB 1	(11/22/2006)
BroadStar Services, LLC	P-1418, SUB 0	(11/02/2006)
Carolina Cable, Inc.	P-1424, SUB 0	(11/22/2006)
Cause Based Commerce Incorporated, d/b/a The Sienna Group	P-1408, SUB 0	(07/24/2006)
Caw Caw Communications, LLC	P-1404, SUB 0	(06/15/2006)
Citicomm of North Carolina, LLC	P-1421, SUB 0	(11/02/2006)
CND Acquisition Corporation	P-1409, SUB 0	(08/24/2006)
CommPartners, LLC	P-1378, SUB 1	(03/21/2006)
Computer Central of Wilson, Inc.	P-1381, SUB 0	(12/11/2006)
Dinamica Telecom, Inc.	P-1411, SUB 0	(08/08/2006)
E-Polk, Inc., d/b/a PANGAEA Internet	P-1315, SUB 2	(11/02/2006)
Fiber Technologies Networks, L.L.C.	P-1388, SUB 1	(03/21/2006)
Fiberlincs, LLC	P-1391, SUB 0	(04/21/2006)
First Communications, LLC, d/b/a First Communications of Ohio	P-1412, SUB 0	(09/15/2006)
Fonix Telecom, Inc.	P-1365, SUB 0	(02/21/2006)
Integrated Services, Inc., d/b/a Integrated Services of Nevada, Inc.	P-1410, SUB 0	(08/08/2006)
IPC Network Services, Inc.	P-1383, SUB 1	(01/13/2006)
Juice Marketing, Inc., d/b/a JMI Telecom	P-1416, SUB 0	(11/02/2006)
Juice Marketing, Inc., d/b/a JMI Telecom	P-1416, SUB 1	(09/29/2006)
LMDS Holdings, Inc.	P-1396, SUB 0	(02/21/2006)

Local & Long Distance Certificates – Issued (Continued)

Company	Docket No.	Date
Master Call Communications, Inc.	P-1392, SUB 0	(03/21/2006)
Multiline Long Distance, Inc.	P-1423, SUB 0	(11/22/2006)
Nationwide Long Distance Service, Inc.	P-1402, SUB 0	(06/15/2006)
New Horizons Communications Corp, d/b/a NHC Communications Inc.	P-1400, SUB 0	(05/02/2006)
Norstar Telecommunications, LLC	P-1413, SUB 0	(09/06/2006)
OPEX Communications, Inc.	P-791, SUB 1	(10/25/2006)
R.T.O. Communications, L.L.C., d/b/a BestWay Phones	P-1256, SUB 1	(11/14/2006)
Shentel Converged Serv., Inc., d/b/a NTC Comm.	P-1422, SUB 0	(12/20/2006)
Shentel Converged Ser., Inc., d/b/a NTC Comm.	P-1422, SUB 1	(11/22/2006)
Silv Communications, Inc.	P-1397, SUB 0	(03/28/2006)
Star Wireless, Inc., d/b/a InterStar Communications	P-1417, SUB 0	(11/02/2006)
Tower Connect, LLC	P-1407, SUB 0	(06/15/2006)
Trans National Communications International, Inc.	P-566, SUB 3	(04/05/2006)
Transamerica Telecom, Inc.	P-1414, SUB 0	(09/06/2006)
TTUSA Acquisition, Inc.	P-1401, SUB 0	(05/02/2006)
United Telecom Inc.	P-1399, SUB 0	(04/11/2006)
USD CLEC, Inc.	P-1406, SUB 0	(05/19/2006)
VCI Company, d/b/a Vilaire Communications, Inc.	P-1390, SUB 0	(01/25/2006)
Windstream Communications, Inc.	P-1394, SUB 0	(06/21/2006)
Yestel, Inc.	P-1398, SUB 0	(04/05/2006)
YMax Communications Corp.	P-1395, SUB 0	(07/21/2006)
3 Voice Communications, Inc.	P-1419, SUB 0	(12/22/2006)
3 Voice Communications, Inc.	P-1419, SUB 1	(12/20/2006)

Bigredwire.com, Inc -- P-1420, SUB 0; Order Denying Application Without Prejudice (12/20/2006)
E-Polk, Inc. – P-1315, SUB 2; Order Reissuing Certificate (11/14/2006)
Integrated Services of Nevada – P-1410, SUB 0; Order Reissuing Certif. Due to Error (08/11/2006)
LDC Telecomm. -- P-470, SUB 4; Order Deny. Applicat. to Provide Long Dist. Serv. (07/25/2006)
Legacy Long Distance International -- P-1173, SUB 1; Recomm. Order Grant. Certificate of Public Convenience and Necessity (07/13/2006)
Network PTS -- P-1350, SUB 1; Recomm. Order Grant. Certificate of Public Convenience and Necessity (07/13/2006)
VCI Company, d/b/a Vilaire Communications, Inc. – P-1390, SUB 0; Order Reissuing Certificate to Correct Error (02/06/2006)

TELECOMMUNICATIONS - Cancellation of Certificate

Local & Long Distance Certificates – Canceled

Company	Docket No.	Date
Adelphia Telecommunications, Inc.	P-648, SUB 3	(03/21/2006)
Affordable Stay, Inc.	P-1295, SUB 1	(06/28/2006)
American Long Lines, Inc.	P-602, SUB 6	(02/21/2006)

Local & Long Distance Certificates – Canceled (Continued)

Company	Docket No.	Date
BasicPhone, Inc.	P-1134, SUB 1	(05/09/2006)
Blue Diode Communications, LLC	P-1373, SUB 1	(07/13/2006)
Claricom Networks, LLC	P-611, SUB 6	(01/06/2006)
Econodial, LLC	P-1203, SUB 1	(09/01/2006)
Epixstar Communications Corporation	P-1230, SUB 1	(10/10/2006)
GTC Telecom	P-821, SUB 2	(01/30/2006)
ICG Telecom Group, Inc.	P-582, SUB 11	(04/27/2006)
KMC Telecom V, Inc.	P-989, SUB 4	(05/24/2006)
Metro Teleconnect Companies, Inc.	P-1186, SUB 2	(01/18/2006)
Nationwide Professional Teleservices, LLC	P-1335, SUB 1	(04/06/2006)
OCMC, Inc., d/b/a One Call Communications	P-1198, SUB 1	(07/13/2006)
Redsquare Corp., d/b/a Redsquare Comm. Corp.	P-1358, SUB 2	(06/15/2006)
Shared Communications Services, Inc.	P-591, SUB 3	(09/22/2006)
SouthernNet, Inc.	P-156, SUB 32	(01/23/2006)
Sail Networks, Inc.	P-1289, SUB 2	(06/14/2006)
Telefyne Incorporated	P-1110, SUB 1	(02/21/2006)
Universal Access, Inc.	P-939, SUB 5	(10/25/2006)
VCI Company, d/b/a Vilaire Communications, Inc.	P-1390, SUB 1	(03/21/2006)

Acceris Communications Corp. – P-1007, SUB 5; Order Canceling Certificates (02/21/2006)
MCI Network Services – P-141, SUB 51; P-671, SUB 8; Order Canceling Certificates (04/20/2006); Errata Order (05/19/2006)
U.S. TelePacific Corp. – P-971, SUB 3; Order Canceling Certificates (01/06/2006)
Utilities Comm., New Smyrna Beach – P-1292, SUB 3; Order Cancel. Certificates (06/20/2006)
Servisense.com, Inc. – P-1009, Sub 2; P-100, SUB 160; Order Affirming Previous Commission Order Canceling Certificate (01/13/2006)

TELECOMMUNICATIONS - Complaint

AT&T Communications of the Southern States, LLC -- P-140, SUB 91; Order Dismissing Complaint and Closing Docket (Carolina Telephone and Telegraph Co. & Central Telephone Co. (12/01/2006)
BellSouth Telecommunications, Inc. -- P-55,
SUB 1577; Order Dismissing Complaint (dPi Teleconnect, L.L.C.) (06/07/2006)
SUB 1641; Order Dismissing Complaint and Closing Docket (C.R. Dolby, Jr.) (06/07/2006)
Long Distance Consolidated Billing Co. -- P-1346, SUB 1; Order Dismissing Complaint and Closing Docket (Jeanette Tannerhill) (05/26/2006)
Verizon South, Inc. -- P-19,
SUB 495; Order Dismissing Complaint and Closing Docket (Mark Lassiter) (01/30/2006)
SUB 500; Order Dismissing Complaint and Closing Docket (Howard Alley) (06/13/2006)

TELECOMMUNICATIONS - Contracts/Agreements

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SUB 141 (MCI Access Transmission Services, LLC) (01/10/2006)
SUB 146 (Granite Telecommunications) (01/10/2006)
SUB 150 (Sprint Spectrum, LP) (03/17/2006)

"Order Approving Agreement(s) and/or Amendment(s)" – Orders Issued (Continued)

ALLTEL Carolina, Inc. – P-118,
SUB 151 (NationsLine North Carolina, Inc.) (04/20/2006)
SUB 152 (Quality Telephone, Inc.) (07/20/2006)
SUB 153 (1-800-RECONEX, Inc.) (10/30/2006)

AT&T Communications of the Southern States, LLC -- P-140,
SUB 51A (Verizon South, Inc.) (01/20/2006)
SUB 73 (BellSouth Telecommunications, Inc.) (01/20/2006)

Barnardsville Telephone Company -- P-75,
SUB 60; P-76, SUB 51; P-60, SUB 71 (06/06/2006)
SUB 61 (Charter Fiberlink NC-CCO, LLC) (07/20/2006)

BellSouth Telecommunications, Inc. -- P-55,
SUB 1228 (Birch Telecom of the South, Inc) (08/31/2006)
SUB 1326 (Sprint Communications Company, LP) (06/30/2006)
SUB 1346 (DIECA Communications, Inc., d/b/a Covad) (03/17/2006)
SUB 1371 (Sprint PCS) (12/21/2006)
SUB 1431 (Xspedius Communications) (09/22/2006)
SUB 1437 (XO Communications Services, Inc.) (01/10/2006); (03/17/2006)
SUB 1445 (ALEC, Inc.) (07/20/2006)
SUB 1452 (Business Telecom, Inc.) (01/20/2006); (03/17/2006)
SUB 1461 (Network Telephone Corporation) (04/20/2006)
SUB 1487 (Cinergy Communications Company) (03/17/2006)
SUB 1499 (American Fiber Network, Inc.) (01/10/2006)
SUB 1511 (US LEC of North Carolina, Inc.) (01/10/2006); (03/17/2006)
SUB 1526 (T-Mobile USA, Inc.) (06/30/2006)
SUB 1528 (Southern Digital Network, Inc.) (03/17/2006)
SUB 1567 (KMC Data, LLC) (03/17/2006)
SUB 1568 (KMC Telecom V, Inc.) (03/17/2006)
SUB 1572 (NationsLine North Carolina, Inc.) (03/17/2006)
SUB 1574 (Covista, Inc.) (03/17/2006)
SUB 1588 (BellSouth Long Distance, Inc.) (11/15/2006)
SUB 1593 (AmeriMex Communications Corp.) (11/15/2006)
SUB 1602 (Kentucky Data Link, Inc.) (01/11/2006)
SUB 1603 (Symtelco, LLC) (01/11/2006); (03/17/2006)
SUB 1604 (Tennessee Telephone Service, LLC) (01/11/2006); (05/19/2006)
SUB 1605 (1-800-RECONEX, Inc. d/b/a USTEL) (01/11/2006)
SUB 1606 (One Point Communications – Georgia) LLC (01/11/2006)
SUB 1607 (SkyBest Communications, Inc.) (01/11/2006)
SUB 1608 (Midwestern Telecommunications, Inc.) (02/23/2006)
SUB 1609 (New East Telephony, Inc.) (01/20/2006)
SUB 1611 (Cricket Communications, Inc.) (02/23/2006)
SUB 1612 (High Country Wireless, Inc.) (02/23/2006)
SUB 1613 (Advent Paging) (02/23/2006)
SUB 1614 (North Carolina Telcom, LLC) (02/23/2006)
SUB 1615 (Esodus Communications) (03/17/2006)
SUB 1617 (Pac-West Telecomm, Inc.) (03/17/2006)
SUB 1618 (NOW Communications & Cleartel Telecomm.) (03/17/2006)
SUB 1620 (IDS Telcom Corporation) (04/20/2006)

"Order Approving Agreement(s) and/or Amendment(s)" – Orders Issued (Continued)

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SUB 1622 (Crystal Clear Connections, Inc.) (05/19/2006)
SUB 1623 (France Telecom Corporate Solutions, LLC) (05/19/2006)
SUB 1624 (Momentum Business Solutions, Inc.) (05/19/2006)
SUB 1625 (Epicus Communications Group, Inc.) (05/19/2006)
SUB 1626 (DSLnet Communications, LLC) (06/06/2006)
SUB 1627 (SBC Long Distance, LLC) (06/06/2006); (09/22/2006); (11/15/2006)
SUB 1628 (TelCove Operations, Inc.) (06/06/2006); (10/30/2006)
SUB 1629 (Sprint Long Distance, Inc.) (06/06/2006); (08/31/2006)
SUB 1631 (AT&T) (06/06/2006); (06/30/2006); (11/15/2006); (12/21/2006)
SUB 1633 (IDT America Corporation) (06/06/2006)
SUB 1634 (TCG) (06/06/2006); (06/30/2006); (11/15/2006); (12/21/2006)
SUB 1636 (NOS Communications, Inc.) (06/06/2006)
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SUB 1638 (Image Access, Inc., d/b/a NewPhone) (06/30/2006)
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SUB 1640 (EveryCall Communications) (06/30/2006)
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SUB 1643 (Kanoy Communications) (07/20/2006)
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ITC^DeltaCom Communications – P-500, SUB 18 (BellSouth Telecomm.) (03/17/2006)

MCImetro Access Transmission Services – P-474, SUB 14 (BellSouth) (11/01/2006)

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ALLTEL Communications, Inc. – P-514, SUB 26; P-1394, SUB 0 Order Approving Transfer of Assets and Customers (07/06/2006)
BCN Telecom, Inc. -- P-581, SUB 5; Order Approving Transfer of Control (04/04/2006)
Birch Telecom of the South -- P-1000, SUB 4; Order Approving Transfer of Control (03/07/2006)
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TELECOMMUNICATIONS – Sale/Transfer (Continued)

New Edge Network -- P-901, SUB 2; Order Approving Transfer of Control (02/21/2006)

Qwest Communications -- P-433, SUB 14; P-977, SUB 2; Order Approving Transfer of Control (07/06/2006)

Sprint Comm. -- P-294, SUB 29; P-817, SUB 3; Order Approv. Transfer of Customers (02/13/2006)

Trinsic Communications -- P-817, SUB 4; P-886, SUB 2; Order Approv. Transfer of Assets and Customers (04/19/2006)

VarTec Telecom, Inc. -- P-362, SUB 9; P-639, SUB 6; P-270, SUB 16; P-1384, SUB 0; Order Approving Transfer of Assets, Customers, and Certificates (05/18/2006)

Vanco Direct USA -- P-1364, SUB 2; P-939, SUB 4; Order Approving Transfer of Assets and Customers (03/28/2006)

Xspedius Management Co. Switched Services – P-1202, SUB 7; Order Approving Transfer of Control (09/29/2006)

TELECOMMUNICATIONS - Securities

Concord Telephone Co. -- P-16, SUB 223; Order Granting Authority to Borrow Funds and Guarantee Loans (04/12/2006)

MebTel Communications -- P-35, SUB 102; P-736, SUB 5; Order Granting Amended Authorization to Transfer Control (11/29/2006)

Randolph Telephone Co. -- P-61, SUB 92; Order Approving Authority to Execute Promissory Note and Secure Loan (03/08/2006)

ALLTEL Carolina, Inc. -- P-118, SUB 149; Order Authorizing Execution of Guarantee and Pledge of Assets (02/22/2006)

TRANSPORTATION

TRANSPORTATION - Adjustments of Rates/Charges

Rates-Truck -- T-825, SUB 340; Order Approving Fuel Surcharge (01/18/2006); (04/11/2006); (05/02/2006); (08/15/2006); (08/29/2006); (09/19/2006); (09/26/2006); (10/03/2006); (10/31/2006); (12/19/2006)

TRANSPORTATION - Common Carrier Certificate

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Ace Movers; Chadwick Lynn Gilreath, d/b/a	T-4324, SUB 0	(05/23/2006)
American Moving & Hauling, Inc.	T-4323, SUB 0	(05/03/2006)
Bill Willis Enterprises; William R Willis, Jr, d/b/a	T-4348, SUB 0	(11/17/2006)
Budget Movers, Inc.	T-4342, SUB 0	(09/11/2006)
Bulldog Moving, LLC	T-4344, SUB 0	(10/13/2006)
Carolina 1st Moving & Services, Inc.	T-4316, SUB 0	(03/20/2006)
Carolina Moving Systems, Inc.	T-4319, SUB 0	(02/16/2006)
Class Action Movers, Class Action, LLC, d/b/a	T-4330, SUB 0	(08/11/2006)
Dedmon Moving and Storage, Inc.	T-4325, SUB 0	(04/18/2006)

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Company	Docket No.	Date
EZ Access Mover; Christopher B. Howell, d/b/a	T-4318, SUB 0	(11/30/2006)
Freeman Boys Courier Service Anthony Tony Freeman, d/b/a	T-4331, SUB 0	(06/15/2006)
Garris Demetrius Evans, d/b/a Saveubucks of America	T-4317, SUB 0	(01/25/2006)
Gentle Giant Moving Company (NC), LLC	T-4321, SUB 0	(02/17/2006)
Heads Up Moving & Freight, Odell Junior McKinney, d/b/a	T-4334, SUB 0	(07/25/2006)
Highway Moving	T-4349, SUB 0	(11/27/2006)
Hood's Movers; Linwood Hood, d/b/a	T-4343, SUB 0	(09/01/2006)
John W. Woodlief Moving and Service Co.	T-4326, SUB 0	(06/21/2006)
John's Service Company of New Bern, Inc.	T-4315, SUB 0	(01/31/2006)
Marrins' Moving Systems, Ltd.	T-4329, SUB 0	(06/06/2006)
Move It Now of Raleigh; CJM Moving, d/b/a	T-4345, SUB 0	(10/02/2006)
Reliable Moving and Storage, Inc	T-4354, SUB 0	(12/14/2006)
This and That Moving and Delivery; C. Britt & G. Farrell, d/b/a	T-4322, SUB 0	(04/24/2006)
Triad Moving Inc	T-4337, SUB 0	(08/30/2006)
Triangle Mobile Storage, LLC	T-4339, SUB 0	(08/09/2006)
Two Men and A Truck of Asheville; AMS & Sons Moving Co., LLC d/b/a	T-4338, SUB 0	(10/20/2006)
World Wide Relocation Services, Inc.	T-4347, SUB 0	(10/20/2006)

Thruway's Packaging Store – T-4288, SUB 0; Order Allowing Withdrawal of Application and Closing Docket (07/07/2006)

TRANSPORTATION - Cancellation of Certificate

Apartment & Office Movers of NC, LLC -- T-4195, SUB 1; Order Canceling Certificate of Exemption (05/17/2006)

Brodie's Moving Service, Ltd -- T-3784, SUB 3; Order Canceling Certificate of Exemption (07/06/2006)

Brooks & Broadwell Realty -- T-4079, SUB 3; Order Canceling Certificate of Exemption (08/14/2006)

D & G Local Movers; Dennis L. Sutton, d/b/a -- T-4182, SUB 1; Order Canceling Certificate of Exemption (06/28/2006)

Every Move You Make, Inc. – T-4183, SUB 1; T-100, SUB 66; Order Affirming Previous Commission Order Suspending Certificate (10/30/2006)

Helpful Movers, Inc -- T-4269, SUB 1; Recommended Order Canceling Certificate of Exemption (04/25/2006)

Monroe, Richard Hugh, Jr., M & B Movers, d/b/a – T-4308, SUB 3; T-100, SUB 66; Order Affirming Previous Commission Order Suspending Certificate (10/30/2006)

Raleigh Bonded Warehouse, Inc. -- T-741, SUB 2; Order Canceling Certificate of Exemption (09/14/2006)

W.W. Owens & Sons Moving & Storage, Inc. -- T-371, SUB 7; Order Canceling Certificate of Exemption (01/31/2006)

TRANSPORTATION - Cancellation of Certificate (Continued)

Quality-One Moving Services & Supplies, LLC – T-4187, SUB 2; T-100, SUB 63; Order Canceling Certificate of Exemption (04/26/2006)

TRANSPORTATION – Complaint

Movers at Demand, Inc. -- T-4176, SUB 1; T-4176, SUB 2; Order Suspending Penalty Payments, Removing Audit Conditions, and Granting Certificate of Exemption (05/09/2006)

TRANSPORTATION - Name Change

A Magic Mover; Seven Cities Relocation Specialists LLC, t/a -- T-4255, SUB 1; Order Approving Name Change (01/05/2006)

Barnes & Barnes Moving; Margaret Hunsucker Barnes d/b/a -- T-2869, SUB 2; Order Approving Name Change (05/22/2006)

Coastal Carriers Moving & Storage Co.; Coastal Carriers, Inc., d/b/a -- T-4174, SUB 3; Order Approving Name Change (05/09/2006)

J.E. Thomas & Sons Moving; John E. Thomas, d/b/a – T-4311, SUB 1; Order Approving Name Change (02/07/2006)

John's Moving & Storage; Outstanding Service Corp., d/b/a -- T-4135, SUB 1; Order Approving Name Change (08/23/2006)

Premium Moving, Inc. -- T-4190, SUB 1; Order Approving Name Change (05/02/2006)

Smooth Movin Services -- T-4284, SUB 1; Order Approving Name Change (04/27/2006)

Southern Moving, Inc. -- T-4206, SUB 2; Order Approving Name Change (08/16/2006)

TRANSPORTATION - Reinstating Certificate

Carolina 1st Moving & Services, Inc. -- T-4316, SUB 1 Order Rescinding Order Canceling Certificate of Exemption (07/10/2006)

Shore to Shore Moving & Storage; Samuel David Shore d/b/a -- T-4137, SUB 2 Order Rescinding Order Canceling Certificate of Exemption (04/07/2006)

Steele & Vaughn Moving; Johnson TV Service Center, Inc., d/b/a -- T-4228, SUB 1; Order Accepting Insurance Form E (10/02/2006)

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Burrows Enterprise, LLC -- T-4270, SUB 3; Recommended Order Canceling Certificate of Exemption (01/30/2006)

Carolina Movers, David Dellinger, d/b/a -- Recommended Order Canceling Certificate of Exemption; T-4233, SUB 1 (03/13/2006)

Shore to Shore Moving & Storage; Samuel David Shore d/b/a -- T-4137, SUB 3; Recommended Order Canceling Certificate of Exemption (07/24/2006)

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ASE Moving Services; American Star Enterprises, Inc., d/b/a -- T-3245, SUB 5 Order Granting Authorized Suspension (12/15/2006)

M & B Movers; Richard Hugh Monroe, Jr. d/b/a -- T-4308, SUB 2; Order Granting Authorized Suspension (07/06/2006)

Raleigh Bonded Warehouse -- T-741, SUB 1; Order Granting Authorized Suspension (04/03/2006)

US-1 Van Lines of North Carolina -- T-4163, SUB 1; Order Granting Authorized Suspension (05/08/2006)

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Murphy Movers; Ralph Wayne Bevins, d/b/a -- T-4290, SUB 1; T-4351, SUB 0; Order Approving Transfer and Name Change (12/14/2006)

WATER AND SEWER

WATER AND SEWER – Bonding

Asheville Property Management, Inc. -- W-1145, SUB 5; Order Approv. Bond and Surety and Releasing Bond and Surety (02/28/2006)

Baytree Waterfront Properties, Inc. -- W-938, SUB 4; Order Approving Bond and Surety and Releasing Bond and Surety (06/16/2006)

Cogdill, Greg S. -- W-1171, SUB 4; Order Approving Bond and Surety and Releasing Bond and Surety (11/13/2006)

Enviro Tech of North Carolina, Inc. -- W-1165, SUB 2; Order Approving Bond and Surety and Releasing Bond and Surety (01/24/2006)

Ginguite Woods Water Reclamation Association, Inc. -- W-1139, SUB 2; Order Approving Bond and Surety and Releasing Bond and Surety (08/11/2006)

Honeycutt; Wayne M. -- W-472, SUB 13 Order Approving Bond and Surety and Releasing Bond and Surety (09/12/2006)

Heater Utilities, Inc. -- W-274, SUB 605; Order Approving Corporate Surety Bond and Releasing Bond (09/27/2006)

JACTAW Properties, LLC -- W-1209, SUB 1; Order Approving Bond and Surety and Releasing Bond and Surety (04/03/2006)

Meadows; Ted and Virginia B. -- W-1197, SUB 3; Order Approving Bond and Surety and Releasing Bond and Surety (01/24/2006)

Pine Island Utilities -- W-999, SUB 3; Order Approving Bond and Surety and Releasing Bond and Surety (11/21/2006)

Pine Island-Currituck LLC -- W-1072, SUB 11; Order Approving Bond and Surety and Releasing Bond and Surety (11/21/2006)

Sandler Utilities at Mill Run LLC -- W-1130, SUB 5; Order Approving Bond and Surety and Releasing Bond and Surety (02/28/2006)

Simpson & Simpson Utilities -- W-1112, SUB 4; Order Approving Bond and Surety and Releasing Bond and Surety (06/13/2006)

Utilities, Inc. -- W-1000, SUB 10; Order Approving Bond and Surety and Releasing Bond and Surety (08/11/2006)

Water Quality Services, Inc. -- W-1099, SUB 8; Order Approving Bond and Surety and Releasing Bonds and Sureties (07/03/2006)

WATER AND SEWER - Cancellation of Certificate

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Ideal Mobile Home Park -- W-748, SUB 2; Order Canceling Franchise (02/23/2006)

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Aqua North Carolina, Inc.	W-218, SUB 237	(10/10/2006)
Aqua North Carolina, Inc.	W-218, SUB 244	(10/02/2006)
Heater Utilities, Inc.	W-274, SUB 439	(08/16/2006)
Heater Utilities, Inc.	W-274, SUB 502	(04/28/2006)
Heater Utilities, Inc.	W-274, SUB 554	(04/28/2006)
Heater Utilities, Inc.	W-274, SUB 555	(02/07/2006)
Heater Utilities, Inc.	W-274, SUB 556	(02/07/2006)
Heater Utilities, Inc.	W-274, SUB 565	(12/19/2006)
Heater Utilities, Inc.	W-274, SUB 576	(06/01/2006)
Heather Utilities, Inc.	W-274, SUB 578	(07/03/2006)
Heather Utilities, Inc.	W-274, SUB 579	(06/01/2006)
Heater Utilities, Inc.	W-274, SUB 580	(07/03/2006)
Heater Utilities, Inc.	W-274, SUB 581; W-337, SUB 13	(08/08/2006)
Heater Utilities, Inc.	W-274, SUB 590	(11/13/2006)
Heater Utilities, Inc.	W-274, SUB 591	(09/08/2006)
Heater Utilities, Inc.	W-274, SUB 592	(09/08/2006)
Heater Utilities, Inc.	W-274, SUB 603	(11/13/2006)

A & D Water Service, Inc. -- W-1049, SUB 9; Order Accepting Bond, Granting Franchise, and Approving Rates (09/25/2006)

Aqua North Carolina, Inc. -- W-218, SUB 167; Order Closing Docket (12/14/2006)

Aqua North Carolina, Inc. -- W-218, SUB 196; Errata Order (08/24/2006)

Cedar Brook Properties -- W-1229, SUB 0 Order Dismissing Application and Closing Docket (10/19/2006)

Clarke Utilities, LLC -- W-1205, SUB 2; Order Accepting Bond, Granting Franchise, and Approving Rates (06/13/2006)

EWGP Retail, LLC -- W-1242, SUB 0; Order Rescinding Order Requiring Bond and Closing Docket (10/11/2006)

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Heater Utilities, Inc. - W-274, SUB 472; Order Revising Certificate of Public Convenience and Necessity (11/30/2006)

Heater Utilities, Inc. -- W-274, SUB 502; Errata Order (05/02/2006)

Heater Utilities, Inc. -- W-274, SUB 555; Reissued Order Granting Franchise and Approving Rates (02/13/2006)

Heater Utilities, Inc. -- W-274, SUB 555; Errata Order (02/15/2006); (04/26/2006)

Heater Utilities, Inc. -- W-274, SUB 567; Order Addressing Rate Base Treatment of Cash Purchase Price of System Assets and Scheduling Evidentiary Hearing (08/30/2006); Order Dismissing Application for Certificate of Public Convenience and Necessity and Closing Docket (09/08/2006)

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Jefferson Landing, LLC -- W-1255, SUB 0; W-1019, SUB 2; Recommended Order Approv. Transfer, Approv. Rate Increase and Requir. Customer Notice (01/30/2006); Order Allowing Recomm. Order to Become Effective and Final (01/30/2006); Errata Order (01/31/2006)

KRJ Utilities Company -- W-1075, SUB 5; Order Granting Certificate of Public Convenience and Necessity and Approving Rates (11/30/2006)

North Chatham Utilities, LLC -- W-1256, SUB 0; Order Closing Docket (02/03/2006)

Rumfelt and Fred T. Luther; Mark E. -- W-1254, SUB 0; Order Accepting Bond, Granting Franchise, and Approving Rates (09/28/2006)

TRG Charlotte, LLC -- W-1257, SUB 0; Order Granting Franchise, Approving Rates, and Requiring Customer Notice (01/31/2006)

WATER AND SEWER – Complaint

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 286; Order Canceling Hearing, Dismissing Complaint and Closing Docket (08/30/2006)

Environmental Maintenance Systems -- W-1054, SUB 8; Order Dismissing Additional Complaint (01/24/2006)

Heater Utilities, Inc. -- W-274, SUB 549; Order Dismissing Complaint and Closing Docket (01/27/2006)

North Topsail Utilities, Inc -- W-1143, SUB 5; Order Granting Complaint in Part (04/03/2006)

WATER AND SEWER - Contiguous Water Extension

"Order Recognizing Contiguous Extension and Approving Rates" -- Orders Issued

Aqua North Carolina, Inc. -- W-218, SUB 230 (02/07/2006); W-218, SUB 232 & W-218, SUB 165 (05/11/2006); W-218, SUB 242 & W-218, SUB 165 (10/02/2006); W- 218, SUB 243 (12/19/2006)

Carolina Water Service, Inc. of North Carolina – W-354, SUB 272 (04/05/2006)

Conleys Creek Limited Partnership -- W-1120, SUB 3 & SUB 4 (05/17/2006)

Fairways Utilities, Inc.; Aqua North Carolina, Inc. d/b/a -- W-787, SUB 26 (10/04/2006); SUB 28 (09/12/2006); SUB 29 (09/13/2006)

Heater Utilities, Inc. -- W-274,

SUB 511 (09/08/2006);	SUB 536 (08/10/2006);	SUB 538 (04/11/2006);
SUB 540 (02/07/2006);	SUB 557 (04/11/2006);	SUB 559 (10/02/2006);
SUB 560 (07/03/2006);	SUB 561 (04/11/2006);	SUB 564 (10/19/2006);
SUB 566 (07/19/2006);	SUB 568 (07/19/2006);	SUB 572 (04/28/2006);
SUB 573 (04/28/2006);	SUB 574 (07/03/2006);	SUB 575 (06/01/2006);
SUB 577 (10/02/2006);	SUB 582 (07/03/2006);	SUB 589 (11/28/2006);
SUB 593 (10/02/2006);	SUB 594 (11/28/2006);	SUB 595 (09/08/2006);
SUB 596 (11/28/2006);	SUB 599 (10/19/2006);	SUB 600 (12/19/2006);
SUB 601 (12/19/2006);	SUB 602 (11/13/2006);	SUB 606 (11/13/2006)

Aqua North Carolina, Inc. -- W-218, SUB 232 & W-218, SUB 165; Errata Order (05/16/2006)

Fairways Utilities, Inc.; Aqua North Carolina, Inc. d/b/a -- W-787, SUB 19; Order Revising Name of Service Area (02/06/2006)

Heater Utilities, Inc. -- W-274, SUB 390; Errata Order (04/11/2006)

Heater Utilities, Inc. -- W-274, SUB 505; Reissued Order Recognizing Contiguous Extension and Approving Rates (07/27/2006)

Heater Utilities, Inc. -- W-274, SUB 572; Errata Order (05/02/2006)

"Order Recognizing Contiguous Extension and Approving Rates" – Orders Issued (Continued)
Pine Island-Currituck LLC -- W-1072, SUB 10 (05/31/2006)

WATER AND SEWER - Contracts/Agreements
Aqua North Carolina, Inc. – W-218, SUB 220; W-787, SUB 25; W-1032, SUB 7; W-989, SUB 7; W-899, SUB 33; W-981, SUB 8; W-274, SUB 478; W-177, SUB 52; W-200, SUB 47; Order Accept. Agreement for Filing and Allow. Utility to Pay Compensat. (08/24/2006)
Bald Head Island Utilities, Inc. -- W-798, SUB 9; Order Closing Docket (02/07/2006)

WATER AND SEWER – Discontinuance
Anderson Water Supply -- W-566, SUB 1; Order Canceling Franchise (05/31/2006)

WATER AND SEWER – Emergency Operator
Community Water Works, Inc. -- W-316, SUB 4; Order Discharging Emergency Operator (01/04/2006)
Hoopers Valley Water Company -- W-794, SUB 4; Order Discharging Emergency Operator and Closing Docket (04/21/2006)
Village Water; Tobacco Branch Village Water System, Inc., d/b/a -- W-504, SUB 7; Order Appointing Emergency Operator and Requiring Customer Notice (06/29/2006)

WATER AND SEWER - Filings Due per Order or Rule
Environmental Maintenance Systems -- W-1054, SUB 7; Order Closing Docket (06/26/2006)
Scientific Water and Sewerage Corporation -- W-176, SUB 33; Order Terminating Collection of Surcharge (10/30/2006)

WATER AND SEWER – Miscellaneous
Butler Water, Inc. -- W-1006, SUB 7; Order Canceling Franchise and Discharging Emergency Operator (03/20/2006)
Clearwater Valley Water -- W-1234, SUB 0; Order Grant. Application for Deregulat. (02/22/2006)
Enviracon Utilities – W-1236, SUB 1; Order Addressing Outstanding Issues (11/28/2006)
Rock Creek Environmental Co. – W-830, SUB 2; Order Approving Transfer (09/12/2006); Errata Order (09/13/2006)
Total Environmental Solutions -- W-1146, SUB 5; Order Approving Financing Arrangement and Execution of Deed of Trust (03/15/2006)

WATER AND SEWER - Rate Increase
A & D Water Service, Inc. -- W-1049, SUB 10; Order Granting Partial Rate Increase and Requiring Customer Notice (10/11/2006)
A & D Water Service, Inc. -- W-1049, SUB 11; Order Granting Rate Increase and Requiring Customer Notice (08/10/2006)
Bradfield Farms Water Co. – W-1044, SUB 10; Order Closing Docket (12/07/2006)
Carolina Pines Utility, Inc. -- W-1151, SUB 2; Order Closing Docket (12/07/2006)
Carolina Water Service -- W-354, SUB 266; Further Order on Compliance Filings (08/14/2006)
Emerald Plantation Utilities, Inc. -- W-1211, SUB 1; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice 1 (08/04/2006); Order Allowing Recommended Order to Become Effective and Final (08/07/2006)

WATER AND SEWER - Rate Increase (Continued)

Holiday Island Property Owners -- W-386, SUB 15; Order Granting Partial Rate Increase and Requiring Customer Notice (02/08/2006)

Holiday Island Property Owners -- W-386, SUB 16; Order Deleting Sections Q and S from Service Area (08/28/2006)

Metro Water Systems, Inc. -- W-1109, SUB 9; Order Granting Rate Increase, Canceling Hearing and Requiring Customer Notice (10/31/2006)

Nero Utility Services, Inc. -- W-1152, SUB 2; Order Closing Docket (12/07/2006)

Ponderosa Enterprises, Inc.; Ponderosa Mobile Home Park, d/b/a -- W-1086, SUB 1; Order Granting Rate Increase, Cancel. Hearing, & Requir. Customer Notice (07/28/2006)

Scientific Water and Sewerage Corporation -- W-176, SUB 32; SUB 30; SUB 29; Order Approving Final Rates and Requiring Notice (04/18/2006)

Transylvania Utilities, Inc. -- W-1012, SUB 7; Recomm. Order Grant. Rate Increase & Requir. Customer Notice (07/28/2006); Order Allow. Recomm. Order to Become Effect. & Final (08/07/2006)

WATER AND SEWER - Restrictions

Aqua North Carolina, Inc. --W-218, SUB 225; Order Discontinuing Mandatory Water Use Restrictions (08/11/2006)

Carolina Water Service, Inc. -- W-354, SUB 289; Order Reinstating Restriction of Water Use and Requiring Customer Notice (05/16/2006)

WATER AND SEWER - Rule Adoption/Revision

Enviracon Utilities -- W-1236, SUB 3; Order Approving Company-Wide Wastewater Rule (08/10/2006)

WATER AND SEWER -- Sale/Transfer

Aqua North Carolina, Inc. -- W-218, SUB 234; W-1231, SUB 1; W-1231; SUB 2; Order Approving Transfer, Approving Rates, and Requiring Customer Notice (08/08/2006)

Carolina Water Service, Inc. of North Carolina - W-354, SUB 33; Errata Order (07/31/2006)

Heater Utilities --W-274,

SUB 520; W-316, SUB 5; Order Approving Interim Rates as Final Rates (01/04/2006)

SUB 548; W-794, SUB 5; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment, and Requiring Notice (02/23/2006); Order Discharging Emergency Operator and Closing Dockets (04/10/2006)

SUB 551; W-587, SUB 8; Order Approving Transfer, Canceling Franchise, Approving Rates, Approving Rate Base Treatment (04/28/2006)

SUB 553; W-717, SUB 6; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment, and Requiring Notice (01/05/2006)

SUB 569; W-675, SUB 4; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment, Canceling Franchise (09/08/2006)

SUB 570; W-338, SUB 3; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment, Canceling Franchise (10/02/2006)

SUB 581; W-337, SUB 13; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment, and Requiring Notice (08/08/2006)

SUB 588; W-791, SUB 6; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment, Canceling Franchise (10/19/2006)

WATER AND SEWER – Sale/Transfer (Continued)

John Henry Oakley -- W-1258, SUB 0; W-1069, SUB 2; Order Approv. Transfer of Assets and Requiring Customer Notice (06/27/2006)

Knox; Linda -- W-1261, SUB 0; W-1035, SUB 7; Order Establishing General Rate Case, Suspending Rates, and Requiring Customer Notice (01/18/2006)

Laurel Hill Water Co.—W-67, SUB 13; Recomm. Order Approv. Transfer (09/01/2006); Order Allowing Recomm. Order to Become Effective and Final (09/06/2006)

Mountain Air Utilities -- W-1148, SUB 2; Order Approving Stock Transfer (03/08/2006)

Snow & Sims, LLC. d/b/a Orchard View Park -- W-1069, SUB 2; Order Canceling Franchise (07/31/2006)

Water Quality Utilities, Inc. -- W-1264, SUB 0; W-1099, SUB 10; Order Accepting Bond, Approving Transfer, and Requiring Customer Notice (11/13/2006)

Water Resources, Inc. -- W-1034, SUB 5; Order Approving Transfer, Canceling Franchise, and Requiring Customer Notice (11/13/2006)

WATER AND SEWER – Tariff

Water Quality Services, Inc. -- W-1099, SUB 9; Order Approving Tariff Revision and Requiring Customer Notice (06/13/2006)

WATER AND SEWER – Tariff Revision for Pass-Through

Order Approving Tariff Revision – Orders Issued

Company	Docket No.	Date
Asheville Property Management, Inc	W-1145, SUB 6	(04/11/2006)
Asheville Property Management, Inc	W-1145, SUB 7	(01/06/2006)
Asheville Property Management, Inc	W-1145, SUB 8	(01/06/2006)
Asheville Property Management, Inc	W-1145, SUB 9	(10/18/2006)
Asheville Property Management, Inc.	W-1145, SUB 10	(10/18/2006)
Asheville Property Management, Inc.	W-1145, SUB 11	(10/18/2006)
Banks; Parks	W-1244, SUB 5	(10/27/2006)
Banks; Parks	W-1244, SUB 6	(10/27/2006)
Carolina Water Service of N. C.	W-354, SUB 300	(11/28/2006)
Chapman; Roy & Betty	W-1247, SUB 1	(10/27/2006)
Chatham Utilities, Inc.	W-1240, SUB 1	(01/18/2006)
Cogdill; Greg S.	W-1171, SUB 5	(11/13/2006)
Graves Evans Enterprises, Inc.	W-1144, SUB 4	(03/20/2006)
Hawk Run Development	W-1238, SUB 3	(10/19/2006)
Indian Creek Mobile Home Park	W-1116, SUB 5	(10/27/2006)
JACTAW Properties, LLC	W-1209, SUB 2	(04/20/2006)
JACTAW Properties, LLC	W-1209, SUB 3	(10/27/2006)
Motley; Clyde J., Locust Grove Mobile Home Park, d/b/a	W-1106, SUB 6	(01/11/2006)
Motley; Clyde J., Locust Grove Mobile Home Park, d/b/a	W-1106, SUB 7	(10/19/2006)
Laurel Wood Utilities, Inc.	W-1155, SUB 4	(10/25/2006)
MECO Utilities Inc.	W-1166, SUB 3	(02/07/2006)
Metro Water Systems	W-1109, SUB 7	(01/11/2006)
Outer Banks/Kinnakeet Associates, LLC	W-1125, SUB 3	(01/26/2006)

Order Approving Tariff Revision – Orders Issued (Continued)

Company	Docket No.	Date
Pine Valley Mobile Home Park, Inc.	W-1131, SUB 5	(10/18/2006)
Sandler Utilities at Mill Run L.L.C.	W-1130, SUB 3	(01/26/2006)
Total Environmental Solutions	W-1146, SUB 6	(08/16/2006)
Wellington Mobile Home Park, Inc.	W-1011, SUB 11	(08/10/2006)
Winkler; Carl K.	W-1206, SUB 4	(10/27/2006)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 293; Order Approving Rate Increase Subject to Refund and Requiring Notice to Customers (07/21/2006)

Christmount Christian Assembly, Inc. -- W-1079, SUB 5; Order Approving Tariff Revision and Requiring Customer Notice (08/01/2006)

Joyceton Water Works -- W-4, SUB 10; Order Approving Tariff Revision and Requiring Customer Notice (05/11/2006)

Mountain Air Utilities. -- W-1148, SUB 3; Order Approving Increased Tap On Fees (07/24/2006)

Outer Banks/Kinnakeet Associates, LLC -- W-1125, SUB 3; Reissued Order Approving Tariff Revision (05/03/2006); Errata Order (01/26/2006)

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
Abberly Green – Mooresville	WR-457, SUB 0	(04/12/2006)
Abbington Place/Charlotte, LLC	WR-453, SUB 0	(03/23/2006)
ACG-CRLP Crescent Matthews LLC	WR-463, SUB 0	(05/10/2006)
Advenir@Monroe 5920, LLC	WR-511, SUB 0	(10/19/2006)
Ashborough Investors, LLC	WR-489, SUB 0	(09/20/2006)
Autumn Wood Apartments, LLC	WR-510, SUB 0	(10/12/2006)
Best Mulch, Inc.	WR-513, SUB 0	(10/27/2006)
BIR Charlotte I, L.L.C.	WR-477, SUB 0	(07/05/2006)
BRC Charlotte 485, LLC	WR-501, SUB 0	(09/29/2006)
BRC Salisbury, LLC	WR-500, SUB 0	(09/29/2006)
BRC Wilson, LLC	WR-502, SUB 0	(10/12/2006)
BVF Paces Arbor, LLC	WR-428, SUB 0	(01/18/2006)
BVF Paces Forest, LLC	WR-427, SUB 0	(01/18/2006)
BVF Wind Lake, LLC	WR-429, SUB 0	(01/18/2006)
C L Properties of the Carolinas, LLC	WR-516, SUB 0	(10/30/2006)
Camden Summit Partnership, L.P.	WR-6, SUB 95	(01/18/2006)
Cranbrook Village Communities, L.L.C.	WR-524, SUB 0	(11/28/2006)
Cambridge NC Warwick, LLC	WR-514, SUB 0	(12/06/2006)
Carolina Oaks Investors, LLC	WR-525, SUB 0	(11/22/2006)
CH Realty III/Durham South Place, LLC	WR-528, SUB 1	(12/05/2006)
CH Realty III/Durham South Place, LLC	WR-528, SUB 2	(12/06/2006)
Concord Warwick, LLC	WR-526, SUB 0	(11/22/2006)

ORDERS AND DECISIONS LISTED

Order Granting Certificate of Authority and Approving Rates – Orders Issued (Continued)

Company	Docket No.	Date
Crescent Commons Apartments, LLC	WR-460, SUB 0	(05/15/2006)
Crescent Oak Apartments, LLC	WR-465, SUB 0	(05/15/2006)
CRLP Mallard Creek, LLC	WR-455, SUB 0	(04/05/2006)
EEA Eastchester Ridge, LLC	WR-509, SUB 0	(11/14/2006)
Empirian Highlands LP, and Empirian Alexander Pointe, LP	WR-508, SUB 0	(10/19/2006)
EQR-Alta Crest, LLC	WR-537, SUB 0	(12/12/2006)
Estates at Meridian, LLC	WR-434, SUB 0	(02/13/2006)
Fayetteville Apartments, LLC	WR-441, SUB 0	(02/13/2006)
Fund IX PR Durham, LLC	WR-518, SUB 0	(11/16/2006)
General Greene, LLC	WR-486, SUB 0	(08/29/2006)
GMC Sun Valley, LLC	WR-456, SUB 0	(04/18/2006)
Greystone WW Company, LLC	WR-517, SUB 0	(11/13/2006)
GS Edinborough Park, LLC	WR-475, SUB 0	(07/05/2006)
GS Edinborough Park, LLC	WR-476, SUB 0	(07/05/2006)
Happy Hill, Inc.	WR-512, SUB 0	(10/12/2006)
Harris Blvd. Communities I, LLC	WR-478, SUB 0	(07/20/2006)
Huntington Woods Communities, LLC	WR-498, SUB 0	(09/13/2006)
Inman Park Investment Group, Inc.	WR-383, SUB 0	(07/05/2006)
Kings Grant Fayetteville, LLC	WR-442, SUB 0	(02/13/2006)
Kingswood Manufactured Home Community	WR-490, SUB 0	(08/29/2006)
Lincoln Green Apartments, LLC	WR-527, SUB 0	(11/22/2006)
LMC Ballantyne, Inc.	WR-515, SUB 0	(11/08/2006)
Lofts at Lakeview, LP	WR-440, SUB 0	(02/27/2006)
Mid-America Apartments, Limited Partnership	WR-22, SUB 14	(04/13/2006)
Mebane Apartments Associates	WR-485, SUB 0	(09/07/2006)
MRP Laurel Oaks, LLC	WR-507, SUB 0	(10/16/2006)
MRP Laurel Springs, LLC	WR-506, SUB 0	(10/12/2006)
Northstone Apartments, LLC	WR-458, SUB 0	(05/01/2006)
Oberlin Court, LLC	WR-369, SUB 0	(01/18/2006)
One Norman Square Limited Partnership	WR-447, SUB 0	(02/27/2006)
Pine Knoll Estates, LLC	WR-471, SUB 0	(08/14/2006)
Premier Properties of Reidsville	WR-464, SUB 0	(05/25/2006)
Princeton Park Apartments, LLC	WR-541, SUB 0	(12/18/2006)
Puller Place, LLC	WR-439, SUB 0	(02/06/2006)
Residence One Morganton, LLC	WR-443, SUB 0	(02/13/2006)
S. E. Portfolio Apartments, LLC	WR-505, SUB 1	(11/22/2006)
Stratford Apartment Properties, LLC	WR-523, SUB 0	(11/22/2006)
SCP Apartments, LLC & Madison-Clinton-Tampa, LLC	WR-451, SUB 0	(03/29/2006)
Shoreline, LLC	WR-530, SUB 0	(11/28/2006)
Spring Ridge Bentley, LLC	WR-472, SUB 0	(06/28/2006)
Summit Green, LLC	WR-539, SUB 0	(12/21/2006)
Varsity Lane Associates, LLC	WR-484, SUB 0	(08/29/2006)
Village Rental Company, LLC	WR-468, SUB 0	(06/06/2006)
Westmont Commons Apartments, LLC	WR-459, SUB 0	(04/25/2006)

Order Granting Certificate of Authority and Approving Rates – Orders Issued (Continued)

Company	Docket No.	Date
Weston Lakeside, LLC	WR-483, SUB 0	(08/22/2006)
188 Claremont, LLC and Silver & Silver Properties, LLC	WR-504, SUB 0	(10/10/2006)

RESALE OF WATER AND SEWER – Certificate

BNP/Chapel Hill, LLC -- WR-481, SUB 0; WR-90, SUB 17; Order Granting Certificate of Authority, Approving Rates, and Canceling Certificate (07/19/2006)

Mid-America Apartments, L.P. -- WR-22, SUB 14; Errata Order (04/28/2006)

Residence Water Services, Inc. -- WR-452, SUB 0; W-1122, SUB 4; Order Granting Certificate of Authority, Approving Rates, and Canceling Franchise (03/23/2006)

RESALE OF WATER AND SEWER - Cancellation of Certificate

Order Canceling Certificate of Authority - Orders Issued

Company	Docket No.	Date
Carolina Oaks Investors, LLC	WR-525, SUB 0 WR-189, SUB 1	(11/27/2006)
Alta Crest; Alta Crest Limited	WR-21, SUB 5	(11/13/2006)
Acquiport Cambridge, Inc.	WR-61, SUB 5	(05/30/2006)
AIMCO/Shadow Lake, LP	WR-147, SUB 4	(11/22/2006)
Camden Summit Partnership, L.P.	WR-6, SUB 96	(12/06/2006)
Camden Summit Partnership, L.P.	WR-6, SUB 97	(12/13/2006)
Consolidated Capital Institutional Properties/3	WR-154, SUB 2	(11/13/2006)
CRIT Landings, LLC	WR-419, SUB 1	(11/22/2006)
Drawbridge Limited Partnership	WR-289, SUB 2	(11/22/2006)
Hunt Management Company	WR-123, SUB 14	(09/19/2006)
Hunt Management Company	WR-123, SUB 15	(09/26/2006)
Hunt Management Company	WR-123, SUB 16	(10/03/2006)
JMG Realty, Inc.	WR-229, SUB 2	(08/10/2006)
NPCA Limited Partnership	WR-140, SUB 2	(12/19/2006)
Orange Grove Park Limited Partnership	WR-170, SUB 2	(11/22/2006)
Olmsted Park Development, LLC	WR-389, SUB 1	(07/31/2006)
Plantation Park Apartments, Ltd.,	WR-31, SUB 6	(09/26/2006)
SCA-North Carolina Limited Partnership	WR-35, SUB 38	(11/29/2006)
SCA-North Carolina Limited Partnership	WR-35, SUB 39	(12/13/2006)
SCA-North Carolina Limited Partnership	WR-35, SUB 40	(12/19/2006)
SCA-North Carolina Limited Partnership	WR-35, SUB 41	(12/19/2006)
SCA-North Carolina Limited Partnership	WR-35, SUB 42	(12/19/2006)
Sea Stratford, LLC	WR-267, SUB 1	(08/29/2006)
Sedgewood Green Apartments, LLC	WR-107, SUB 3	(10/10/2006)
Sterling Apartments, LLC	WR-90, SUB 18	(08/10/2006)
Sterling Apartments, LLC	WR-90, SUB 19	(08/10/2006)
TCR Place Limited Partnership	WR-131, SUB 4	(12/05/2006)
The Villages of Eastover Glen, LLC	WR-382, SUB 1	(07/31/2006)

RESALE OF WATER AND SEWER - Cancellation of Certificate (Continued)

Alexander Development, LLC-- WR-136, SUB 6; Order Canceling Certificate of Authority and Requiring Customer Notice (10/16/2006)

Autumn Woods Associates, LLC -- WR-28, SUB 6; Order Canceling Certificate of Authority and Requiring Customer Notice (09/06/2006)

Cedars Apartments Associates, LLC -- WR-283, SUB 1; Order Canceling Certificate of Authority and Requiring Customer Notice (08/28/2006)

Davis Commons Lexington, LLC -- WR-410, SUB 1; Order Canceling Certificate of Authority and Requiring Customer Notice (09/12/2006)

Links at Eastwood, LLC -- WR-175, SUB 3; Order Canceling Certificate of Authority and Requiring Customer Notice (11/13/2006)

Northview Asheville, LLC -- WR-355, SUB 1; Order Canceling Certificate of Authority and Requiring Customer Notice (10/11/2006)

Schaedle Worthington Hyde Properties, LP - WR-143, SUB 6; Order Canceling Certificate of Authority (01/11/2006)

Tarrant Road Apartment Associates, LLC -- WR-334, SUB 1; Order Canceling Certificate of Authority and Requiring Customer Notice (10/17/2006)

THC Hamptons, L.P. -- WR-17, SUB 3; WR-470, SUB 0; Order Canceling Certificate of Authority and Disapproving Application for Certificate of Authority (06/30/2006)

Waterford Creek, LLC -- WR-1, SUB 4; Order Canceling Certificate of Authority and Requiring Customer Notice (10/31/2006)

RESALE OF WATER AND SEWER – Complaint

Strickland Farms General Partnership -- WR-174, SUB 1; Order Dismissing Complaint and Closing Docket (Nancy Seymour) (03/22/2006)

RESALE OF WATER AND SEWER - Sale/Transfer

"Order Granting Transfer of Certificate of Authority and Approving Rates" – Orders Issued

Beechwood Triad Apt. Portfolio -- WR-496, SUB 0; WR-3, SUB 107; (09/14/2006)

BNP/Abbington, LLC -- WR-454, SUB 0; WR-62, SUB 20 (04/13/2006)

BNP/PACES COMMONS, LLC -- WR-488, SUB 0; WR-59, SUB 38 (09/20/2006)

BNP/Pepperstone, LLC -- WR-445, SUB 0; WR-62, SUB 19 (02/28/2006)

BNP/Savannah, LLC -- WR-474, SUB 0; WR-62, SUB 21 (06/21/2006)

BNP/Waterford, LLC -- WR-444, SUB 0; WR-62, SUB 18 (02/28/2006)

CH Realty III/Durham South Place -- WR-528, SUB 0; WR-386, SUB 1 (11/22/2006)

Colonial Alabama L.P. -- WR-437, SUB 0; WR-143, SUB 8 (01/31/2006)

Columbia Vinoy, LLC -- WR-531, SUB 0; WR-11, SUB 9 (11/29/2006)

Concord, LLC -- WR-426, SUB 0; WR-87, SUB 3 (01/11/2006)

Covington Meridian LeaseCo, LLC -- WR-425, SUB 0; WR-274, SUB 1 (01/04/2006)

CRLP McCullough Drive, LLC -- WR-538, SUB 0; WR-402, SUB 1 (12/06/2006)

CRLP Shannopin Drive, LLC -- WR-408, SUB 0; WR-13, SUB 2 (01/18/2006)

CRLP University Ridge Drive, LLC -- WR-487, SUB 0; WR-57, SUB 8 (09/07/2006)

CRLP-Crabtree, LLC -- WR-436, SUB 0; WR-143, SUB 7 (02/13/2006)

Deerwood Crossing Triad Apt. Portfolio -- WR-494, SUB 0; WR-3; SUB 105 (09/14/2006)

DREF Waterford Hills, LLC -- WR-480, SUB 0; WR-66, SUB 7 (08/29/2006)

Dutch Village Triad Apt. Portfolio -- WR-491, SUB 0; WR-3, SUB 102 (09/27/2006)

Fairfield Cornerstone, LLC -- WR-469, SUB 0; WR-216, SUB 4 (06/21/2006)

RESALE OF WATER AND SEWER - Sale/Transfer (Continued)
"Order Granting Transfer of Certificate of Authority and Approving Rates" – Orders Issued
Fairfield Poplar Place, LP -- WR-473, SUB 0; WR-216, SUB 5 (06/13/2006)
Highland Quarters, LLC -- WR-520, SUB 0; WR-308, SUB 2 (11/22/2006)
Juniper Antlers Lane, LLC -- WR-430, SUB 0; WR-153, SUB 4 (01/24/2006)
Juniper Carriage House, LLC -- WR-432, SUB 0; WR-144; SUB 4 (01/24/2006)
Juniper Quail Woods, LLC -- WR-431, SUB 0; WR-120, SUB 3 (01/24/2006)
Juniper Reddman, LLC -- WR-433, SUB 0; WR-142, SUB 3 (01/24/2006)
Kayser Enterprises Two, LLC -- WR-435, SUB 0; WR-123, SUB 12 (02/20/2006)
Kings I Paces, LLC -- WR-448, SUB 0; WR-39, SUB 70 (03/17/2006)
Kings I Summerwalk, LLC -- WR-449, SUB 0; WR-414, SUB 2 (03/07/2006)
Lake Brandt Triad Apt. - - WR-495, SUB 0; WR-3, SUB 106 (09/14/2006)
MB Remington Place, LLC -- WR-461, SUB 0; WR-39, SUB 71 (08/14/2006)
MB The Timbers, LLC -- WR-462, SUB 0; WR-39, SUB 72 (04/25/2006)
Northwinds Triad Apt. Portfolio -- WR-492, SUB 0; WR-3, SUB 103 (09/14/2006)
Park Forest Triad Apt. Portfolio -- WR-493, SUB 0; WR-3, SUB 104 (09/14/2006)
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