NINETY-FIFTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2005 THROUGH DECEMBER 31, 2005

NINETY-FIFTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2005, through December 31, 2005

Jo Anne Sanford, Chair

J. Richard Conder, Commissioner[1]

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

Michael S. Wilkins, Commissioner[2]

Howard N. Lee, Commissioner[3]

Robert K. Koger, Commissioner[4]

North Carolina Utilities Commission
Office of the Chief Clerk
Mrs. Geneva S. Thigpen
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

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

[1] Commissioner Conder's term ended June 30, 2005.
[2] Commissioner Wilkins resigned from the Commission effective February 28, 2005.
[3] Commissioner Lee was appointed April 1, 2005.
[4] Commissioner Koger served from July 1, 2005, through December 5, 2005.

LETTER OF TRANSMITTAL

December 31, 2005

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, 2005, we hereby present for your consideration the report of the Commission's decisions for the 12-month period beginning January 1, 2005, and ending December 31, 2005.

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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Robert K. Koger, Commissioner

Geneva S. Thigpen, Chief Clerk

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DOCKET NO. E-100, SUB 56

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Decommissioning Costs for Nuclear Power Plants Owned and Operated by Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.; Duke Power, a Division of Duke Energy Corporation; and Virginia Electric and Power, d/b/a Dominion North Carolina Power	)	ORDER RULING ON 2004 COST STUDIES AND FUNDING REPORT OF DUKE POWER

BY THE COMMISSION: On November 3, 1998, the Commission issued an Order in this docket which adopted Guidelines for the Determination and Reporting of Nuclear Decommissioning Costs (Guidelines).

Pursuant to the Guidelines, on June 10, 2004, Duke Power, a division of Duke Energy Corporation (Duke, or Company) filed its 2004 Decommissioning Cost Studies for the Catawba, McGuire, and Oconee nuclear units (the cost studies). According to Duke, the 2004 cost studies determined that the estimated site-specific nuclear decommissioning costs for the Company's ownership interest in these nuclear units totaled approximately $2.3 billion. The previous cost studies in 1999 estimated a decommissioning cost of $1.9 billion, or $2.2 billion in 2003 dollars at 3% inflation.

On October 11, 2004, Duke filed its 2004 Decommissioning Cost and Funding Report (the funding report). Duke's 2004 funding report indicates that the decommissioning revenue requirement or expense for the North Carolina retail jurisdiction is approximately $35 million annually, which would be a $15 million, or 30%, decrease from the approximate $50 million nuclear decommissioning expense being recorded on the Company's books. Since the annual decommissioning revenue requirement/expense calculated by Duke in the 2004 funding report varies by more than 15% from the annual decommissioning expense being recorded on Duke's books, the following parties filed reports on April 11, 2005, recommending actions the Commission should undertake as a result of Duke's 2004 cost studies and funding report: Duke and the Public Staff, jointly; the Carolina Utilities Customer Association Inc. (CUCA); and the Attorney General's Office (AGO).

On May 16, 2005, the Commission issued an Order Allowing Comments in response to the reports of the parties filed on April 11, 2005. Such reply comments were due on May 31, 2005.

On May 31, 2005, Duke and the Public Staff jointly filed reply comments. CUCA and the AGO also separately filed reply comments.

A summary of the parties' reports and recommendations and reply comments is presented below.

REPORTS AND RECOMMENDATIONS

Duke and the Public Staff's
Joint Report and Recommendations

Duke and the Public Staff's Joint Report and Recommendations (the Joint Report) notes that Duke's 2004 funding report is the first such report ever filed by Duke to indicate a material difference between the existing and projected funding levels (i.e., $50 million being recorded on the Company's books versus $35 million calculated by Duke in the 2004 funding report). According to Duke, this increase is directly related to the renewal by the Nuclear Regulatory Commission (NRC) of Duke's operating licenses for each of its nuclear units. Although site-specific cost studies in 1994 and 1999 revealed rather substantial increases in the estimated nuclear decommissioning costs, the funding level remained relatively constant due to other factors such as the earnings rates on decommissioning funds. Accordingly, Duke has sought no change in annual collections and funding levels since its last general rate case in 1991.

The Joint Report points out that the impacts of the following factors are incorporated in Duke's 2004 funding report:

1. Elimination of the Use of Internal Funds

The Commission issued an Order Requiring Transition of Internal Decommissioning Funds in this docket on February 5, 2004. In April of 2004, Duke transferred all of its internally reserved balance of approximately $262 million to the external nuclear decommissioning fund, and now, Duke externally funds 100% of its decommissioning obligation.

2. Levelized Funding Approach

Duke's 2004 funding report is a discounted cash flow analysis, combining the new decommissioning cost estimates from the 2004 cost studies with assumptions regarding future cost escalation and trust fund earnings. An annuity is calculated from the results to provide for an annual levelized funding of expected decommissioning costs. The Joint Report states that, historically, the nuclear depreciation rate was increased to include an amount covering the decommissioning annuity needed for the external trust fund and the internal fund. Duke now recommends eliminating the decommissioning component of the nuclear depreciation rate, and instead, specifying that future funding of the trust funds for the estimated nuclear decommissioning costs should be based on the total annuity calculation. The Public Staff agrees with this recommendation.

3. Impact of License Renewal

The Joint Report states that the reduction in the decommissioning annual revenue requirement shown in Duke's 2004 funding report is directly related to the extended life of the nuclear plants, and the corresponding extension of the funding period, arising from the renewed operating licenses. There were minimal decommissioning cost increases resulting from the license renewals. However, the extended time period provides potential for a larger fund growth. The net effect of license renewal is for fund growth to outpace expense escalation. In projecting funding requirements, the time period used by Duke in the 2004 funding report assumes shutdown five years prior to the actual license expiration date granted by the NRC. All currently shutdown nuclear units reached the end of their economic lives well before the end of their licensed lives. Based on the historical evidence of premature shutdowns, Duke believes it is prudent to assume shutdown prior to the end of the licensed life. Therefore, Duke's 2004 funding report reflects a 15-year life extension rather than the 20-year extension granted by the NRC.

4. Cost Escalation and Fund Earnings Estimates

Duke believes that key components of the funding analysis are the assumptions for cost escalation of nuclear decommissioning and the investment returns on the decommissioning trust funds. Based on a review of both historical cost and earnings levels, and incorporating investment mixes for the trust funds projected by fund managers, Duke estimates a cost escalation rate of 4%, a qualified trust fund earnings rate of 5%, and a non-qualified trust fund return of approximately 4.5%, and uses these assumptions in calculating the annual decommissioning revenue requirement or expense in the 2004 funding report.

The Cost Escalation Rate: Duke reports that a review of decommissioning cost studies since 1989 reveals additional cost escalation over the 13-year average inflation rate of 2.5%. For the period 1994-1999, the additional cost escalation over inflation was approximately 9%, but the additional escalation was only approximately 1.7% for the period 1993-2003. In the 2000 funding report, Duke used an overall cost escalation rate of 5.5%, which was the sum of a 3% inflation rate and 2.5% for the additional escalation of costs. In the 2004 funding report, the Company elected to use the more current escalation rate of approximately 1.7%, which when combined with a prospective inflation rate of 2.5%, results in an approximate 4% overall cost escalation rate.

Trust Fund Earnings Rate: With respect to investment returns, the projected net-of-tax return was derived by applying an expected return of each class of investment in the trust to the average allocation of the trust, less fees and anticipated taxes. The short-term or money market returns used by Duke are based on the historical inflation rate of 2.5% to 3%. The fixed income investments are expected to earn the risk-free rate of 5% to 5.5% as determined from the use of the forward yield curve. And finally, the portfolio of equity investments are expected to earn a 3% risk premium over the risk-free rate, or approximately 8% to 8.5%. The Joint Report states that the application of these return estimates to the average trust allocation, coupled with a 20% tax rate for all income, dividends, and realized capital gains, results in a return in the approximate range of 4.9% to 5.3% for the qualified trust. Returns for the non-qualified trust are projected to be in the approximate range of 4.3% to 4.7%, assuming a conservative average asset allocation, tax-exempt securities for fixed-income investments, and use of the Company's corporate tax rates.

The Joint Report states that the Public Staff is concerned that the projected net-of-tax returns appear to be very conservative. Information reviewed by the Public Staff suggests that the trust fund earnings rates could be as much as 1% higher than the returns projected by Duke and used in its 2004 Funding Report calculation. According to the Public Staff's analysis, the after-tax returns could be as high as 6.6% for the qualified trust and 5.8% for the non-qualified trust. The Public Staff noted that Duke reduced its projected escalation and return rates significantly from 2000 to 2004 and its projected trust fund returns are lower than its actual fund returns over the past 13 years. In addition, although there are numerous sources of projected returns available, Duke used projections from one source. The Public Staff's review of a source for long-range projections and a source for long-term historical data both indicate potentially higher returns than Duke employed, which may indicate a lower annual revenue requirement or expense for nuclear decommissioning.

However, Duke believes the expected return assumptions are well supported. Duke states that the current market environment with low inflation and low rates is much different than the strong equity growth environment of the 1990s, when higher returns were earned. Duke believes it is prudent to be conservative in drawing conclusions when using short-term market performance data to estimate potential long-term market returns. Duke's investment advisors suggest that an increase in the acceptance of equity risk by investors has gradually lowered the required real returns on equity from historical averages. Duke selected a 3% risk premium as recommended by its investment advisors from a plausible range of 2% to 6%.

Given the Public Staff's concerns regarding the trust fund earnings rate, Duke has agreed to do the following:

1. File a report of actual return results for each trust fund when available on an annual basis;

2. Review return assumptions for both trusts periodically and file reports on any significant changes to return projections; and

3. Consider two or more different sources of projections in its assessment of estimated returns for future decommissioning cost and funding reports.

With these commitments, the Public Staff accepts Duke's projected returns for purposes of this report, but reserves the right to request the Commission to further investigate Duke's return projections at any time.

5. Jurisdictional Factor

The Commission approved Guidelines provide that "the jurisdictional factor used by [Duke] to allocate nuclear production plant shall be used to determine the portion of the nuclear decommissioning costs which may be collected from the Company's North Carolina retail ratepayers. This factor shall be the one approved by the Commission in the Company's most recent general rate case." The North Carolina retail jurisdictional allocation factor established in Duke's last general rate case, Docket No. E-7, Sub 487, is 61.7443%. The 61.7443% factor was based on Duke's 1990 North Carolina retail total summer demand at the generation level as a percentage of the 1990 system total summer demand at the generation level.

Duke proposes that the portion of the total nuclear decommissioning revenue requirement attributable to the North Carolina retail jurisdiction should be based on the North Carolina retail demand factor included in the cost of service study filed annually with the Commission. Based on Duke's 2003 North Carolina retail total summer demand at the generation level as a percentage of the total system summer demand at the generation level, the North Carolina retail jurisdiction allocation factor is 71.1761%. Using the 71.1761% factor, Duke calculated an annual decommissioning revenue requirement or expense of approximately $35 million. Duke recommends use of the most current jurisdictional factor because it provides for the proper allocation of total funding requirements. The Public Staff agrees that nuclear decommissioning costs and funding amounts should be allocated to the North Carolina retail jurisdiction using the most current allocation factor, rather than the factor established in Docket No. E-7, Sub 487.

The summary of the Joint Report states that Duke has developed projections of decommissioning costs and earnings of trust funds for many decades into the future. These projections, by their nature, are a forward-looking snapshot in time, upon which conclusions must be drawn regarding the adequacy of decommissioning funding levels. Duke and the Public Staff believe that the 2004 cost studies and 2004 funding report incorporate the most current information available and reasonable projections and that the indicated funding level provides reasonable assurance funds will be available when needed to decommission the nuclear facilities. Further, as future studies are undertaken, the periodic updates required by the NRC and the Commission will provide timely mechanisms to adjust funding levels and should serve to mitigate any concerns related to appropriate funding.

Specifically, Duke and the Public Staff request an order from the Commission:

1. Accepting Duke's filed 2004 Nuclear Decommissioning Cost Analyses and its 2004 Decommissioning Cost and Funding Report and finding the total revenue requirement/funding amount and related calculations therein reasonable without need for a hearing or further investigation as proposed by CUCA.

2. Finding that the North Carolina retail portion of the total revenue requirement/funding amount will be based on Duke's cost of service study filed annually with the Commission pursuant to Docket No. E-7, Sub 487. Using the 2003 cost of service study, the North Carolina retail cost of service amount for nuclear decommissioning expense is as follows:

Unit	Total Cost per 2004 Study(1) (in thousands)	Revenue Requirement/Annual Funding (in millions)	
		System	NC Retail(2)
Oconee 1	$350,500	$7	$5
Oconee 2	$343,200	$6	$5
Oconee 3	$491,300	$10	$7
McGuire 1	$448,400	$10	$7
McGuire 2	$562,100	$13	$9
Catawba 1	$56,000	$1	$1
Catawba 2	$69,000	$2	$1
Total	$2,320,500	$49	$35

(1) In 2003 dollars
(2) N.C. retail computed as follows: Annual System Total x Jurisdictional Allocation Factor. The 2003 cost of service study reflects a 71.1761% jurisdictional allocation factor for N.C. retail.

3. Requiring Duke to reduce its nuclear depreciation rate to eliminate any impact for nuclear decommissioning costs.

4. Implementing the updated nuclear decommissioning funding level effective January 1, 2005.

CUCA's Report and Recommendations

CUCA filed Nova Energy Consultants, Inc.'s Analysis of Duke Power's Report on Nuclear Decommissioning (Nova's Analysis) and requests that the Commission schedule an evidentiary hearing to consider the issues raised by Nova's Analysis as described below.

Nova's Analysis notes that Duke has received renewed operating licenses from the NRC for each of its nuclear units since Duke filed its previous funding report on June 13, 2000. Given the license renewal, the earliest date at which any of the licenses now expire will be in 2031. By that time, Nova hopes that lessons learned from the earlier decommissioning of other units can be applied to the Duke units so that the total cost of decommissioning the Duke units will not be as high as currently estimated.

Nova's Analysis includes a comparison of the returns on investments used by Duke to calculate the annual revenue requirement in its 2004 funding report to the returns earned by such investments over the historical period of 1926 to 2003. For common equities, Duke assumed a return of 8% to 8.5%, or a risk premium of 3% over the return on U.S. Treasuries. In comparison, over the 1926 to 2003 time period, equity securities earned a higher return of no less than 10.4%, and a higher risk premium of 6.7%, using a geometric mean. For fixed income securities, Duke used returns of approximately 5% to 5.5%, which are roughly one-half of a percent lower than the return on fixed income securities over the 1926 to 2003 time period. For short-term or money market investments, Duke used returns of 2.5% to 3%, which are consistent with the long-term historical returns for such short-term investments.

Nova's Analysis also cites and compares certain assumptions used by Duke in calculating the annual decommissioning revenue requirement in the funding report filed by Duke on June 13, 2000. In that filing, Duke assumed a projected escalation rate of 5.5% for nuclear decommissioning, a 7.0% return on the qualified trust and a 6.5% return on the non-qualified trust. Nova noted that the above rates of return equate to an investment spread of 1.5% on the qualified trust and 1% on the non-qualified trust over the 5.5% escalation rate. Nova explained that these investment spreads are a barometer through which the investments can outpace inflation and thereby lessen the amount of the annuity required to decommission Duke's nuclear units. Nova stated that the annual decommissioning revenue requirement from Duke's funding report filed on June 13, 2000 equaled $43,873,000. Using the license extensions granted to the nuclear units since Duke's 2000 filing, Nova calculated a lower annual revenue requirement equal to $29,828,000 using the North Carolina retail allocation factor of 61.74% and the same investment spreads that were used by Duke in the 2000 filing. According to Nova, the $29,828,000 figure represents the annual revenue that Duke would have proposed to expense in the 2004 funding report if it had used the same allocation factor and investment spreads which Duke used in its 2000 filing. Further, Nova pointed out that Duke now proposes to use the allocation factor of 71.1761%. According to Nova, Duke did not provide an adequate explanation of the proposed allocation difference in its 2004 filing. However, the annual revenue requirement calculated by Nova using the 71.1761% allocation factor equals $34,383,000.

According to Nova's Analysis, Duke has also earned 6.5% on its qualified trust and 8.2% on its non-qualified trust over the period 1992 through 2003. However, Duke used an earned return of only 5.5% on the qualified trust and a 5% return on the non-qualified trust in calculating the annual revenue requirement of approximately $35 million in its 2004 funding report. Nova states that, while this difference might seem small, such a difference is huge given the large sums of money involved in this process as well as the time over which these returns can accumulate. Nova adds that it is unfortunate that Duke did not provide any basis for using investment returns that were markedly different from the returns exhibited by these funds in years past.

Nova's Analysis also recalculated the annual decommissioning revenue requirement using different assumptions to assess the impact such changes would have on the annual revenue requirement or annuities. According to Nova, the most critical aspects of the decommissioning analysis are the escalation rates and the rates of return on the trusts. The higher the investment spreads employed in the analysis, the lower the resulting annuity will be. In its calculations, Nova used the 4.0% escalation factor used by Duke in its 2004 funding report as well as the investment spreads of 1.5% for the qualified trust and 1.0% for the non-qualified trust which were used by Duke in its 2000 funding report. Nova stated that it chose not to change any factor used by Duke other than the escalation factors and the assumed rates of return. The annual revenue requirement or annuity calculated by Nova equaled $21,952,000, using the investment spreads in Duke's 2000 funding report and the 61.74% NC retail allocation factor. When Nova repeated this same calculation with the only difference being the use of Duke's proposed 71.1761% allocation factor, the annuity equaled $25,309,000. This annuity is approximately $9 million less than the approximate $35 million recommended by Duke and the Public Staff.

In summary, Nova recommends that the annuity amount that Duke is allowed to expense each year should be no more than $21,952,000, which is derived using the 61.74% allocation factor established in Duke's last general rate case and the investment spreads used by Duke in its funding report filed on June 13, 2000. Nova contends that Duke has dramatically changed its earnings assumptions in its 2004 funding report as compared to its 2000 filing and, that, in light of historical returns from the past 77 years and the actual returns on the decommissioning trusts, there is no basis for such a change. Nova states that Duke's proposed annual revenue requirement or expense of approximately $35 million is $8 million to $9 million per year higher than can be justified, and if the proposed revenue requirement is approved, Duke's NC retail customers will pay anywhere from $200 million to $225 million in excessive payments before Duke's first nuclear unit is decommissioned. Nova believes that the Commission should immediately open a docket to examine Duke's apparent funding discrepancy.

Nova adds that another concern for Duke's ratepayers is that the higher annual revenue requirement or expense calculated by Duke will also allow the utility to accrue higher expenses, thereby leading to lower reported returns by the utility. The lower reported returns would eventually lead to rates which are higher than necessary and retard economic development.

The Attorney General's Report

The AGO's report includes no comment on the expense level and calculations proposed in Duke's 2004 funding report, but provides notice that it may wish to file reply comments on the reports of the other parties and to participate in further proceedings.

REPLY COMMENTS

Duke and the Public Staff's
Joint Reply Comments

In reply comments, Duke and the Public Staff state that there are essentially two issues remaining in dispute between those parties and CUCA based on their earlier reports and recommendations. The first issue concerns whether Duke used appropriate rates of return on the decommissioning trusts and the second issue concerns whether Duke used an appropriate factor to allocate annual decommissioning expenses to the North Carolina retail jurisdiction.

Duke submits that the expected return assumptions set forth in its study are well supported. Duke notes that the Public Staff and CUCA questioned whether Duke's projected earnings rates were too conservative. However, the Public Staff accepted Duke's projected trust fund earnings rates for the purpose of determining the current funding level, with Duke agreeing to: (1) file a report of actual return results when available on an annual basis; (2) review the return assumptions for both trusts periodically and file reports on any significant changes to return projections; and (3) consider two or more sources in its assessment of estimated returns for future Decommissioning Cost and Funding Reports.

Further, Duke and the Public Staff believe that the study results present the most current information available, that the projections are reasonable, and that the indicated funding level provides reasonable assurance funds will be available when needed to decommission the nuclear units. In addition, as future studies are undertaken, the periodic updates required by the NRC and the Commission will provide timely mechanisms to adjust funding levels and mitigate any concerns related to appropriate funding.

Finally, based upon all of the foregoing and the detailed support provided in their Joint Report, Duke and the Public Staff submit that a hearing or any further investigation is unnecessary and contrary to the interests of judicial economy. Accordingly, Duke and the Public Staff request that the Commission issue an order as specifically recommended in their Joint Report.

CUCA's Reply Comments

CUCA believes that the Commission must schedule an evidentiary hearing to address both: (1) the appropriate rates of return on Duke's decommissioning trust funds and (2) the appropriate jurisdictional allocation factor. CUCA submits that the issues raised by the parties' reports involve factual disputes that can only be resolved properly through a contested evidentiary hearing that provides opportunity for cross-examination after discovery.

CUCA notes that Duke currently records $50 million annually for decommissioning expense and funding and that Duke's calculations and 2004 funding report indicate that Duke can reduce its annual decommissioning revenue requirement to $35 million annually. The $35 million figure is based on Duke's estimates of an escalation rate of 4%, a qualified trust fund return of 5%, a non-qualified trust fund return of 4.5%, a jurisdictional allocation factor of 71.1761% and significant life extensions for Duke's nuclear units. In contrast, Nova's Analysis, completed on behalf of CUCA, concludes that the annual revenue requirement should be reduced to $21,952,000, or $13 million per year lower than Duke's proposal. Nova notes that Duke has reduced its earnings assumptions and Nova believes that in light of historical earnings, as well as returns actually earned on the trust funds, there is no basis for Duke to make such a change. CUCA contends that Duke's proposal to file additional reports of actual return results, review return assumptions and consider different sources of return projections are meaningless as ratepayer protections. CUCA states that the window to modify a nuclear decommissioning revenue requirement effectively opens only once every five years and ratepayers should not be required to pay $65 million in excessive expenses in exchange for reports and consideration of two or more sources of financial projections in five years.

The Commission established a jurisdictional allocation factor of 61.7433% in Duke's last general rate case. CUCA argues that Duke's proposed nuclear decommissioning revenue requirement is overstated through the application of a 71.1761% factor that has not been tested in an evidentiary hearing and that this allocation factor must be subject to testing and challenge by the parties to this proceeding.

CUCA also contends that the appropriate rates of return, escalation rates and allocation factors are the same types of factual issues presented in a general rate proceeding and that such issues cannot be lawfully resolved in this proceeding without an evidentiary hearing. Further, CUCA states that the Public Staff's acceptance of Duke's proposal does not permit the Commission to accept Duke's proposal and would be contrary to the due process requirements articulated by the North Carolina Supreme Court in State ex rel. Utilities Comm'n v. Carolina Utility Customers Ass'n., Inc., 348 N.C. 452, 500 S.E.2d 693 (1998). CUCA submits that this Court decision clearly prohibits adoption of a stipulation "unless the Commission is able to independently conclude that such a stipulation is 'supported by the substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented.'" 348 N.C. at 466, 500 S.E.2d at 703.

CUCA posits that it should be allowed an evidentiary hearing notwithstanding the rate freeze enacted by G.S. 62-133.6 for two reasons. First, although Duke's rates are fixed through December 31, 2007, a general rate proceeding may be initiated if Duke "persistently earns a return substantially in excess of the rate of return established and found reasonable by the Commission in the investor-owned public utility's last general rate case." This statutory exception confirms the need for Duke to record its expenses accurately and reasonably during the rate freeze period. Second, the rate freeze will terminate in approximately 2.5 years, but CUCA states that the annual decommissioning revenue requirement set in this proceeding will be set for 5 years, an interval that extends beyond the end of the rate freeze period.

<u>The AGO's Reply Comments</u>

The AGO points out that the central issues before the Commission are how much of a decrease should be made in the amount that Duke expenses annually for decommissioning funding purposes and whether an evidentiary hearing is needed to reach that determination.

With respect to the evidentiary hearing issue, the AGO concludes that the reporting mechanism now before the Commission is not linked to a rate proceeding, and as such, the AGO does not believe that the issue warrants an evidentiary hearing.

Also, the AGO does not support a reduction in funding to an amount below what was used in Duke's last general rate case unless there will be an opportunity for customers to benefit from such a decrease in funding through a commensurate rate reduction or revenue deferral. Given that Duke's rates are frozen until 2008 under G.S. 62-133.6, a determination that Duke is over-funding decommissioning trusts would not serve a beneficial purpose, aside from improving the accuracy of Duke's earnings reports, unless the Commission also finds that one of the exceptions in G.S. 62-133.6 provides a basis for rate relief or revenue deferral, e.g., that the NRC license extensions constitute governmental action or that Duke's earnings are excessive and a rate decrease or revenue deferral is in the public interest.

The AGO points out that, in recent filings concerning the appropriate level of decommissioning funding for Dominion NC Power, the AGO commented that it was appropriate to consider a reduction in the amount of decommissioning funding in the context of a general rate case that was then pending for Dominion NC Power. The AGO also expressed doubts about the reasonableness of reducing the funding requirement outside of a ratemaking proceeding. Similarly and consistently, the AGO does not support a reduction in funding for decommissioning of Duke's nuclear units to an amount that is less than what was used in Docket No. E-7, Sub 487, Duke's last general rate case in 1991. However, the AGO acknowledges that the Order Granting Partial Rate Increase in that Docket, dated November 12, 1991, identified a decommissioning expense of $33,867,000, whereas the funding amount identified in the Joint Report of Duke and the Public Staff proposes a reduction from the approximately $50 million expensed in 2003 to approximately $35 million for 2005.

The AGO also believes that a reduction in funding to an amount that is less than what was established in Duke's last rate case would not be perceived as fair and just if rates were not adjusted or revenues deferred. The AGO states that money collected for decommissioning, but not set aside for that purpose, would be seen as a windfall to shareholders. According to the AGO, there is no apparent harm in setting aside more than adequate funds until the expense level is altered in a rate proceeding and doing so could serve to mitigate a need for increases if cost projections rise in the future. Further, the AGO opines that it would not be inconsistent for the Commission to making a finding that a funding increase is required in the public interest, whereas a funding decrease is not, since different considerations come into play for an increase versus a decrease. For example, an increase may be required in order to provide adequate funding, but there does not appear to be a comparable public interest reason to reduce the funding level except as part of a ratemaking proceeding.

The AGO acknowledges there is a valid argument that utility books should be adjusted to reflect the most recent information about costs so that records are more accurate, and that such an adjustment may provide more impetus for a possible finding that Duke would have excess earnings. However, the AGO believes that decommissioning expenses are not like most expenses, because they are not expected to be incurred for many years and will then be very large. Further, trusts have been formed to ensure that monies collected in rates for decommissioning will be available in the future when needed. In summary, the AGO states that such trusts should continue to be funded unless there is a public interest reason for reducing such contributions.

CONCLUSIONS

Pursuant to the Guidelines adopted by the Commission in its Order dated November 3, 1998, Duke has filed its five-year, site-specific nuclear decommissioning cost studies and a funding report. All parties have had an opportunity to conduct discovery concerning the details of the cost studies and the funding report. Further, since Duke's 2004 funding report indicates that the NC retail annual expense level calculation of approximately $35 million varies by more than 15% from the NC retail annual expense amount of approximately $50 million being recorded on the Company's books, all parties have had an opportunity to file reports recommending what actions or adjustments, if any, should be taken as a result of the difference.

Duke essentially proposes to change the method or approach which it uses to determine the annual expense or funding amount by eliminating the decommissioning component of the nuclear depreciation rate established in its last general rate case, Docket No. E-7, Sub 487. Instead, Duke requests approval to base future decommissioning expenses and funding levels on the total annuity calculation and its cost of service study filed annually with the Commission pursuant to the Commission's final order in Docket No. E-7, Sub 487, and this approach would become effective retroactive to January 1, 2005. Using this proposed approach, Duke calculates and recommends approval of a NC retail cost of service amount for nuclear decommissioning expense equal to approximately $35 million. The Public Staff essentially agrees with Duke's proposal, subject to certain commitments and agreements with Duke, as described hereinabove.

CUCA believes that Duke's calculation of its approximately $35 million decommissioning expense is overstated for two reasons. First, CUCA challenges the rates of return which Duke estimates that the trust funds will earn. Second, CUCA also challenges the appropriateness of the 71.1761% factor used by Duke to allocate the system decommissioning expense to the North Carolina retail jurisdiction. CUCA asserts that these types of issues cannot be lawfully resolved in this proceeding without an evidentiary hearing and recommends that the Commission issue an order scheduling an evidentiary hearing to address both the appropriate investment spreads between the rates of return on the trust funds and the escalation rate and the appropriate jurisdictional allocation factor.

The AGO does not believe the present matter warrants an evidentiary hearing because it is not linked to a rate proceeding. The AGO does not support a reduction in funding to an amount below what was used in Duke's last general rate case unless there is a commensurate rate reduction or revenue deferral for the benefit of customers.

With respect to CUCA's request to hold an evidentiary hearing, the Commission concludes that it is not required to hold an evidentiary hearing to lawfully resolve the matters at issue in this proceeding and that, further, there is no compelling practical reason to hold such a hearing. There will be no change in rates or service to any Duke customer as a result of a decision by the Commission in this proceeding regarding the appropriate level of decommissioning expense and funding by Duke. All parties have been afforded ample opportunity for discovery and allowed to file comments with the Commission on two separate occasions to express their concerns and make recommendations on Duke's proposal. In addition to the procedural process which has been followed in this matter, the Commission believes that the information which has been filed in this proceeding provides a reasonable basis upon which to make an appropriate decision. Finally, given all of the reasons stated above, the Commission also believes that an evidentiary hearing would be contrary to the interests of judicial economy. In making this decision, the Commission recognizes that this proceeding will be open for a number of years and the Commission has a process in place to periodically review decommissioning expense issues under the Guidelines. Therefore, the Commission's decision not to hold a hearing at this time is without prejudice to its right to convene an evidentiary hearing in the future at any point in time which the Commission deems appropriate.

The Commission notes that Duke, the Public Staff, and CUCA all agree that Duke's annual nuclear decommissioning expense and funding level should be reduced. The AGO agrees there is a valid argument that utility books should be adjusted to reflect the most recent information about costs so that records are more accurate. The AGO does not express any disagreement with the proposed calculations or amounts and sees no apparent harm in over-funding pending review in a rate proceeding. The AGO simply does not support a reduction in funding to an amount below what was used in Duke's last general rate case. However, the AGO acknowledges that the Commission Order dated November 12, 1991, issued in Duke's last general rate case, Docket No. E-7, Sub 487, identified a decommissioning expense of $33,867,000 for the NC retail jurisdiction. Further, given the fact that all of Duke's nuclear units have been granted license extensions of 20 years by the NRC, in conjunction with the considerations that the 2004 cost studies indicate minimal increases in the total cost of decommissioning and that the growth of the trust is expected to outpace expense escalation, the Commission is convinced that some reduction in the annual decommissioning expense and funding level is warranted and can be safely implemented.

As previously discussed herein, Duke proposes, and the Public Staff agrees, to eliminate the decommissioning component of the nuclear depreciation rate and to determine the future expense levels and funding of the trusts based on its annuity calculation. Using the annuity method or approach, Duke calculates an annual expense or funding amount of approximately $35 million for the NC retail jurisdiction, using an allocation factor equal to 71.1761% from its 2003 cost of service study. CUCA does not specifically address Duke's proposal to change to an annuity calculation, but challenges the projected rate of return on the trust funds used by Duke in the calculation of the annuity as well as the allocation factor. Nova's Analysis, performed on behalf of CUCA, points out that the projected returns used by Duke for the common equity and fixed income types of investments in the trusts are less than the earned returns for these types of investments over the time period 1926 through 2003. In addition, Nova's Analysis notes that Duke's 2000 filing used a projected escalation rate of 5.5%, a 7% return on the qualified trust and 6.5% on non-qualified trust, which equated to an investment spread of 1.5% on the qualified trust and a 1% investment spread on the non-qualified trust. However, in its 2004 filing, Duke uses an escalation rate of 4%, a 5% return on the qualified trust and a 4.5% return on the non-qualified trust which equates to an investment spread of 1% on the qualified trust and .5% on the non-qualified trust. After reviewing Duke's 2004 filing, Nova states that it does not find an adequate explanation for the use of the lower expected returns on the trusts. Nova's Analysis also compares the returns earned by Duke on the qualified and non-qualified trusts over the period 1992 through 2003 to the returns projected by Duke on those trusts in its 2004 filing and states that Duke does not provide any basis for using returns in its 2004 filing that are markedly different from the returns earned by the trusts.

In defense of its projected returns, Duke states that the expected return assumptions are well supported. Duke believes that the current low inflation and low interest rate market environment is much different than the strong equity growth environment of the 1990s, when higher returns were earned, and that it is prudent to be conservative when using short-term market performance to estimate long-term market returns. Duke states that its investment advisors suggest a rise in the acceptance of equity risk by investors has gradually lowered the required real rate of return on equity from historical averages. Further, according to Duke, the historical data does not point to a specific equity risk premium, but supports a range of plausible values extending from 2% to 6%. Duke selected a 3% risk premium on the advice of its investment advisors and opines that the 3% risk premium reflects the uncertainty that an increasing number of investors will continue to have on expected returns going forward.

The Commission concludes that the projected return assumptions used by Duke in its annuity calculation are reasonable and appropriate for purposes of this proceeding. The Commission believes that Duke has provided adequate support for its return projection assumptions. The Commission notes that the Public Staff accepts the return projection assumptions used by Duke, based on the agreement and commitment of Duke to file reports on the actual returns earned by the trusts, review its return projections periodically and file reports on any significant changes, and consider two or more different sources of projections in future Decommissioning Cost and Funding Reports. CUCA, through Nova's Analysis, provides comparisons of historical earnings levels and return projections used by Duke in prior years. However, such comparisons are not dispositive, can be endless, and neither CUCA nor Nova make a convincing argument as to what different and specific return projections should be used in the annuity calculation.

CUCA also challenges Duke's use of a 71.1761% factor to allocate the total system nuclear decommissioning expense to the NC retail jurisdiction. Nova's Analysis uses the allocation factor of 61.7443% established by the Commission in Duke's last general rate case. According to Nova, Duke did not provide an adequate explanation of this allocation difference. However, the Commission notes that the Joint Report states that the 71.1761% allocation factor was based on Duke's 2003 NC retail total summer demand at the generation level as a percentage of the 2003 system total summer demand at the generation level. Further, the Joint Report clearly explains that Duke and the Public Staff recommend use of the most current jurisdictional factor because it provides for the proper allocation of the expense amount and funding requirements as opposed to the allocation factor established by the Commission in 1991. Therefore, for the reason stated above, the Commission concludes that the proper allocation factor for purposes of this proceeding should be based on Duke's cost of service study filed annually with the Commission pursuant to the Order in Docket No. E-7, Sub 487, consistent with the Duke and Public Staff recommendation.

In summary, the Commission concludes that the joint proposal of Duke and the Public Staff should be adopted. The net effect of the Commission's decisions on the individual issues as described hereinabove will be to reduce the annual NC retail decommissioning expense and funding level of Duke from approximately $50 million to approximately $35 million. In contrast, CUCA and Nova's recommendation would reduce the $50 million amount to approximately $22 million. Given all the available information and projections at this time concerning the expected nuclear decommissioning costs and required funding levels for Duke, the Commission believes its decisions will result in the appropriate level of reduction in the annual funding amount while preserving the ultimate goal of the Commission in this docket, which is to provide reasonable assurance that adequate decommissioning funds are available when decommissioning costs are incurred by Duke. The Commission's decision as described herein does not restrict the Commission's right to review and require changes to Duke's nuclear decommissioning expense and funding amount in the future without corresponding changes in rates. Finally, the Commission encourages Duke to use the annual expense savings of $15 million arising from the reduction in the Company's nuclear decommissioning expense accrual to increase the level of amortization of Clean Smokestacks costs that otherwise would have been recorded by the Company.

IT IS, THEREFORE, ORDERED:

1. That Duke's 2004 Nuclear Decommissioning Cost Studies and its 2004 Decommissioning Cost and Funding Report is hereby accepted and the total revenue requirement/funding amount and related calculations therein are reasonable;

2. That the North Carolina retail portion of the total revenue requirement/funding amount will be based on Duke's cost of service study filed annually with the Commission pursuant to Docket No. E-7, Sub 487. Using the 2003 cost of service study, the North Carolina retail cost of service amount for nuclear decommissioning expense is as follows:

Unit	Total Cost per 2004 Study(1) (in thousands)	Revenue Requirement/Annual Funding (in millions)	
		System	NC Retail(2)
Oconee 1	$350,500	$ 7	$ 5
Oconee 2	$343,200	$ 6	$ 5
Oconee 3	$491,300	$10	$ 7
McGuire 1	$448,400	$10	$ 7
McGuire 2	$562,100	$13	$ 9
Catawba 1	$56,000	$ 1	$ 1
Catawba 2	$69,000	$ 2	$ 1
Total	$2,320,500	$49	$35

(1) In 2003 dollars
(2) N.C. retail computed as follows: Annual System Total x Jurisdictional Allocation Factor. The 2003 cost of service study reflects a 71.1761% allocation factor for the N.C. retail jurisdiction.

3. That Duke is hereby required to reduce its nuclear depreciation rate to eliminate any impact for nuclear decommissioning costs;

4. That the updated nuclear decommissioning funding level shall be implemented effective January 1, 2005;

5. That CUCA's request for an evidentiary hearing is denied; and

6. That the Commission's decisions as described herein do not restrict the Commission's right to review and require changes to Duke's nuclear decommissioning expense and funding amounts in the future without corresponding changes in rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of July, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Commissioner Robert K. Koger did not participate in this decision.

mr072905.01

DOCKET NO. E-100, SUB 83

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation of Proposed	)	ORDER ADOPTING
Net Metering Rule	)	NET METERING

BY THE COMMISSION: On May 18, 2005, the North Carolina Sustainable Energy Association (NCSEA) filed a letter in the above-captioned docket requesting that the Utilities Commission resume this proceeding which had previously been continued by joint request of the NCSEA and other parties.

On June 2, 2005, the Commission issued an Order granting the NCSEA's request, reopening this proceeding, and establishing a schedule for parties to file briefs on the remaining legal/policy issues.

On August 5, 2005, briefs were filed by the NCSEA, the Public Staff, and the Attorney General. Also on August 5, 2005, a joint brief was filed by 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; jointly, Utilities).

POSITIONS OF THE PARTIES

The commenters note that many of the issues raised at the beginning of this proceeding have now been addressed. Specifically, the recent adoption of small generator interconnection standards has resolved a number of technical issues. In addition, decisions by the Federal Energy Regulatory Commission (FERC) have dismissed the argument that net metering is preempted under the Public Utility Regulatory Policies Act of 1978 (PURPA).

The remaining issue, as succinctly stated by the Utilities, is: whether or not certain customers who own small generators behind the billing meter are entitled to a credit above the utility's energy credit. The Utilities argue that allowing a net metering customer to run the meter backwards during times of excess generation effectively compensates that customer at full retail prices for the excess electricity generated. This full retail rate "includes not only generation-related operating and fuel costs, but the fixed costs of poles, wires, generation assets, etc. and even operating costs such as billing and customer service." Allowing net metering, the Utilities argue, provides a subsidy to those customers at the expense of a utility's other customers.

The Public Staff identifies the issue similarly in its comments, stating that the still-outstanding concerns against net metering "include concerns about discrimination and cross-subsidies because a net metering customer could impose demand and consume energy during on-peak periods, while generating during off-peak periods, would pay a utility nothing for standby service and transmission and distribution facilities, and could impose additional administrative costs and burdens." The Public Staff cites studies, however, that have found numerous benefits from net metering, including: a reduction in peak demand; lessening the consumption of fossil fuels; reducing pollution and avoiding environmental damage; reducing line losses and improving efficiency of the grid; and avoiding upgrades to transmission and distribution facilities. The Public Staff notes that a study conducted in Maryland concluded that the impact on both the utility and its customers is minimal when the net-metered systems are limited to a small percentage of utility peak load. The Public Staff believes that any program should be limited in terms of the types of generation included, the size of individual facilities, and the overall megawatts on a per utility basis. The Public Staff recommends size limits per generator of 10 kW for residential customers and 100 kW for non-residential customers. The Public Staff further recommends a per utility limit of 25 customers, or 0.2% of peak load, whichever is less. Lastly, the Public Staff recommends that any excess generation over summer and winter billing periods be granted to the utility as compensation for standby or other services, thus offsetting the costs being borne by other ratepayers.

The Attorney General in his brief also supports the adoption of "true" net metering. The Attorney General analogizes self-generation to other forms of conservation and argues that the Commission should not discourage such efforts by attaching additional charges to these customers' bills. The Attorney General further argues that the utility is fully compensated because the energy delivered to the grid by the net metering customer is sold by the utility at the full retail rate to a neighboring customer. The Attorney General acknowledges that some net metering customers may replace energy consumed on-peak with off-peak generation, but also argues that solar photovoltaic (PV) facilities, which generally provide on-peak generation, actually benefit the utility by reducing peak demand. Lastly, the Attorney General cities a number of environmental benefits that would be gained by the generation of additional electricity using renewable resources.

The NCSEA in its comments notes that 39 states and the District of Columbia have all adopted some form of net metering. While acknowledging that any excess generation placed on the utility grid results in a "credit" for the generator, the NCSEA analogizes net metering to adding a cup of water to a bucket for later use – "you may not get the exact water you put in, but you can measure out the same amount of water you put in." The NCSEA also notes that net metering allows a small generator to utilize all the electricity produced without having to bear the expense of installing and maintaining a battery system. The NCSEA further acknowledges that net metering customers may be thus subsidized by the utility's other customers, but argues that any such subsidy "would be extremely small." The NCSEA argues, however, that net metering provides a number of benefits to the utility, including simplified accounting for customer generators, reduction in transmission and distribution line losses, reduction in reactive power losses, reduction in the demand for spinning reserve capacity, increase in reliability, voltage support, and deferral of system upgrades. The NCSEA offered a revised model net metering rule for adoption by the Commission. The NCSEA recommends size limits per generator of 20 kW for residential customers and 100 kW for non-residential customers corresponding to the limits currently approved in the small generator interconnection docket. The NCSEA further recommends a per utility limit of 1% of peak load and that excess generation credits be rolled over from month-to-month for 12 months, with payment at avoided cost rates at the end of the 12-month period.

DISCUSSION AND CONCLUSIONS

The Commission previously adopted small generator interconnection standards which allow a utility customer to interconnect and operate a renewable energy facility in parallel with an electric utility. Net metering refers to the billing arrangement whereby the customer-generator is billed according to the difference over a billing period between the amount of energy consumed by the customer at its premises and the amount of energy generated by the renewable energy facility. "True" net metering allows the customer-generator to receive a billing credit for excess generation delivered to the utility grid. Net metering proponents advocate the use of a single meter allowed to spin forward and backward to automatically credit the customer-generator for this excess generation.

The Commission notes that all parties concede that allowing net metering will result in the potential for subsidies for those customers. A number of other benefits, however, have been advanced that could potentially offset any such subsidies. On balance, recognizing the benefit of additional renewable electric generation in this state, the Commission concludes that this represents an appropriate next step forward and that Duke, Progress, and Dominion, therefore, should be required to allow "true" net metering with a single meter on a limited basis.

Net metering, therefore, shall be made available to a utility customer that owns and operates a solar PV, wind-powered, or biomass-fueled renewable energy facility without battery storage. The renewable energy facility may have a capacity of up to 20 kilowatts (kW) for a residential customer-generator and 100 kW for a non-residential customer-generator.

The renewable energy facility shall be interconnected and operated in parallel with an electric utility's distribution system. Each utility shall offer to make net metering available to customer-generators on a first-come, first-served basis in conjunction with its approved small generator interconnection standards up to an aggregate limit of 0.2% of the utility's North Carolina jurisdictional retail peak load for the previous year.

A customer-generator that desires to net meter shall be on, or switch to, a time-of-use demand rate schedule. If the electricity supplied by the utility exceeds the electricity delivered to the grid by the customer-generator during a monthly billing period, the customer-generator shall be billed for the net electricity supplied by the utility, including any demand or other charges under the applicable time-of-use demand rate schedule. If the electricity delivered to the grid by the customer-generator exceeds the electricity supplied by the utility during a monthly billing period, the customer-generator shall be billed for the applicable demand and other charges for that billing period and shall be credited for the excess kilowatt-hours generated during that billing period. The utility shall not charge the customer-generator any standby, capacity, metering, or other fees or charges other than those approved for all customers under the applicable time-of-use demand rate schedule. The kilowatt-hour credit, if any, shall be applied to the following monthly billing period, but shall be reset to zero at the beginning of each summer and winter billing season as defined in the utility's tariff. Similarly, any renewable energy credits (REC), or green tags, associated with this excess generation shall also be granted to the utility when the excess generation credit balance is zeroed out.

The Commission's approval of net metering in this docket reasonably balances numerous factors while attempting to limit the potential for abuse. Net metering is specifically designed for owners of small-scale renewable generation installed for the customer's own use, not for sale to the utility. As such, a net metering customer-generator will not typically apply for a certificate of public convenience and necessity and cannot participate in NC GreenPower. The requirement that excess seasonal generation (and associated RECs) be granted to the utility will appropriately limit the size of individual facilities, yet allow a customer-generator to utilize the full output of its renewable energy facility.

Contrary to the NCSEA's water analogy, all electricity is not valued equally – on-peak generation is valued more highly than off-peak generation. Therefore, excess off-peak generation should be available only during other off-peak hours, not during on-peak hours. Limiting eligibility to renewable energy facilities that do not have battery storage and requiring that a customer be on, or switch to, a time-of-use demand rate schedule address these concerns raised about the potential mismatch of off-peak generation and on-peak consumption. In addition, a time-of-use demand rate schedule more appropriately compensates the utility for any standby capacity than does a time-of-use energy rate schedule. Lastly, by limiting the amount of generation per utility and the size of each eligible renewable energy facility, the Commission concludes that no limit is necessary on the number of net metering customers.

The Commission intends to continue to review the implementation and use of net metering. The utilities, therefore, will be required to file with the Commission annual reports indicating the numbers of net metering applicants and customer-generators, the aggregate capacity of net metered generation, the size and types of renewable energy facilities, the amounts of on-peak and off-peak generation credited and ultimately granted to the utility, and the reasons for any rejections or removals of customer-generators from net metering.

IT IS, THEREFORE, ORDERED as follows:

1. That Progress, Duke, and Dominion shall file in this docket no later than December 1, 2005, tariffs or riders to allow net metering as ordered herein to be effective on or before January 1, 2006;

2. That Progress, Duke, and Dominion shall file on or before December 1 of each year, beginning December 1, 2006, in Docket No. E-100, Sub 83A an annual report indicating the numbers of net metering applicants and customer-generators, the aggregate capacity of net metered generation, the size and types of renewable energy facilities, the amounts of on-peak and

off-peak generation credited and ultimately granted to the utility, and the reasons for any rejections or removals of customer-generators from net metering;

3. That the PV riders allowed to become effective for Progress and Duke by Order dated August 4, 2000, shall be closed effective January 1, 2006, and timely notice of this decision provided to existing customers; and

3. That existing customers on the PV riders shall be transferred to a time-of-use demand rate schedule with net metering effective January 1, 2006, unless they notify their utility no later than December 15, 2005, of their desire to opt out.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of October, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Commissioner Howard N. Lee did not participate in this decision.
Ah101305.03

DOCKET NO. E-100, SUB 100

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER ESTABLISHING
Biennial Determination of Avoided Cost	)	STANDARD RATES AND
Rates for Electric Utility Purchases from	)	CONTRACT TERMS FOR
Qualifying Facilities – 2004	)	QUALIFYING FACILITIES

BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission under G.S. 62-156(b) to establish rates for small power producers as that term is defined in G.S. 62-3(27a).[1]

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of state regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and sell electric power to, cogeneration and small power

[1] The Commission recognizes that the Energy Policy Act of 2005, signed into law on August 8, 2005, has modified various sections of PURPA; however, none of these modifications affect this decision.

production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become "qualifying facilities" (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

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

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

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

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

On June 9, 2004, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing. That Order made Carolina Power and Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC), Duke Power, a division of Duke Energy Corporation (Duke), Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion), and Western Carolina University (WCU) parties to this proceeding to establish the avoided cost rates each is to pay for power purchased pursuant to the provisions of Section 210 of PURPA and the associated FERC regulations and G.S. 62-156. The Order also required each electric utility to file proposed rates and proposed standard form contracts. The Order stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, written statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on these statements, exhibits and schedules, rather than a full evidentiary hearing. PEC, Duke, Dominion, and WCU were required to file their statements and exhibits by November 1, 2004. Other persons desiring to become parties were allowed to intervene and file their statements and exhibits by January 4, 2005. All parties were allowed to file reply comments and proposed orders. The Commission scheduled a public hearing for January 25, 2005, solely for the purpose of taking nonexpert public witness testimony. Finally, the Commission required PEC, Duke, Dominion and WCU to publish notice and submit affidavits of publication no later than the date of the hearing.

The following parties' petitions to intervene were granted: Carolina Industrial Group for Fair Utility Rates I and II (CIGFUR), Craven County Wood Energy Limited Partnership (CCWE), the North Carolina Sustainable Energy Association (NCSEA), and Calpine Corporation (Calpine).

The Commission held a hearing on January 25, 2005, and the following public witnesses testified at this hearing: Theresa Kostrazewa, on behalf of Garth Boyd of Smithfield Foods, Inc., and Murphy Brown, LLC, and John Delafield. Ms. Kostrazewa's statement indicated that the pork industry could not absorb the risks from the new technologies that can convert the carbon in pig manure into energy under the current public policy landscape. She stated that avoided cost payments are too low and that it was imperative that the Commission address the ownership of green tags and conclude that they belong to the QF. Mr. Delafield, who is a solar designer and builder and has signed one of the first agreements with the GreenPower program to provide solar energy, testified that the ownership of green tags was a current issue that needed to be resolved in the QFs' favor and that simplified tariff and interconnection procedures should be approved for the GreenPower program.

NCSEA filed its Initial Statement on February 17, 2005. Calpine and CCWE filed Initial Comments on February 22, 2005. The Public Staff filed an Initial Statement on February 23, 2005. Duke, PEC, Calpine, and the Public Staff filed Reply Comments on April 1, 2005.

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

Based on the foregoing, all of the parties' comments and exhibits, the public witness testimony, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PEC should offer long-term levelized capacity payments and energy payments for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of 10-years and 15-years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed

upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. PEC shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity.

2. Duke should offer long-term levelized capacity payments and energy payments for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of 10-years and 15-years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Duke shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity.

3. Dominion should offer long-term levelized capacity payments and energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of 10-years and 15-years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Dominion shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity. Dominion shall offer long-term levelized energy payments as an additional option for QFs rated at 100 kW or less capacity.

4. PEC, Duke, and Dominion should offer QFs not eligible for the standard long-term levelized rates the following three options if the utility has a Commission-recognized active solicitation underway: (1) participating in the utility's competitive bidding process, (2) negotiating a contract and rates with the utility, or (3) selling energy at the utility's Commission-established variable energy rate. If the utility does not have a Commission-recognized active solicitation underway, PEC, Duke, and Dominion should offer QFs not eligible for the standard long-term levelized rates the options of (1) contracting with the utility to sell power at the variable energy rate established by the Commission in these biennial proceedings or (2) contracting with the utility to sell power at negotiated rates. If the utility does not have a solicitation underway, such negotiations will be subject to arbitration by the Commission at the request of either the utility or QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate; however, the Commission will only arbitrate if the QF is prepared to commit its capacity to the utility for a period of at least two years. In either case, whether there is an active solicitation underway or not, QFs not eligible for the standard long-term levelized rates have the option of selling into the wholesale market. The exact points at which an active solicitation should be regarded as beginning and ending for these purposes should be determined by motion to, and order of, the Commission. Unless there is such a

Commission order, it will be assumed that there is no solicitation underway. If the option of the variable energy rate is chosen, such rate may not be locked in by a contract term, but shall instead change as determined by the Commission in the next biennial proceeding.

5. PEC and Duke use the peaker method to develop avoided capacity costs. Dominion uses the differential revenue requirement (DRR) methodology. Both the peaker method and the DRR method are generally accepted and used throughout the electric utility industry and are reasonable for use in this proceeding.

6. A performance adjustment factor of 2.0 should be utilized by both PEC and Duke for their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation.

7. A performance adjustment factor of 1.2 should be utilized by both PEC and Duke for their respective avoided cost calculations for all QFs in this proceeding except hydroelectric facilities with no storage capability and no other type of generation.

8. Duke's capacity rates used to calculate avoided capacity costs should continue to be based on actual investment costs that would be avoided because of the existence of a QF rather than on market data. Duke shall recalculate and file avoided capacity credits that include a value for capacity in 2005 and 2006.

9. The sale of power by QFs at avoided cost rates does not convey the right to renewable energy credits or green tags.

10. The variable energy rates established by the Commission in these biennial proceedings shall continue to be the "as available" avoided cost energy rates.

11. Capacity in excess of the contract capacity of standard-rate QF generators must be consumed internally by the QF.

12. PEC's proposed revision to its capacity credits should be approved.

13. No change to PEC's treatment of holidays that fall on the weekend is required.

14. Duke's proposal to eliminate its current Option A set of on-peak and off-peak hours in Schedule PP should be rejected. However, Duke should be permitted to offer Option B as an additional option available to QFs.

15. Investigation of issues related to interconnection costs is not appropriate as a part of this proceeding.

16. The rate schedules and standard contract terms and conditions proposed in this proceeding by PEC, Duke, and Dominion should be approved, except as otherwise discussed herein. The utilities shall file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order. The new rate schedules and standard contracts should be allowed to go into effect 10 days after they have been filed. The utilities' filings should stand unless specific objections as to the accuracy of the calculations and conformity to the decisions herein are filed within that 10-day period.

17. PEC, Duke, and Dominion shall each file supporting documentation showing the calculations made to arrive at their avoided cost rates, highlighting any additional changes required by this Order.

18. WCU's proposed Small Power Production Supplier Reimbursement Formula is reasonable and appropriate. WCU should not be required to offer any long-term levelized rate options to QFs.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-3

PEC's Position

In this docket, PEC has proposed to restrict the availability of the standard rate to generators with capacities of 100 kW or less (unless they are solar, wind, hydro, landfill gas, and/or waste generators). PEC asserted that it is appropriate to restrict the availability of the standard rates in this manner for three reasons. First, PEC cited the FERC rule contained in 18 C.F.R. 292.304(c), which only requires a utility to establish standard rates for QFs with a design capacity of 100 kW or less. Secondly, PEC argued that, because the Commission has repeatedly recognized that standard fixed rates increase the risk to the utility, its customers and the QF, long-term forecasted rates most assuredly will be higher or lower than the utility's actual cost over the term the standard rates will be in effect and, therefore, the Commission should limit the availability of such standard rates to the greatest extent possible. Finally, because it is now proposing to offer the standard fixed rates to solar, wind and non-animal waste biomass generators, PEC argued in its Reply Comments that there is no basis for providing the standard rates to any other type of QF except as expressly required by the FERC's regulations. PEC emphasized that there is no State policy supporting the provision of standard rates to any other type of QF that would justify the risks that are created when a utility is required to purchase electricity from a QF at standard rates.

Duke's Position

Duke noted that whether the Commission should require the electric utilities to offer long-term levelized rates to QFs as standard rate options has been an issue in prior avoided cost proceedings and is an issue in this proceeding as well. Fixed rates for 10-year and 15-year contract terms (or for any specified term length, for that matter) are not required by state law or federal law. Long-term levelized rates are permitted, but not required, by the regulations implementing PURPA. G.S. 62-156(b)(1) states that "long term contracts shall be encouraged in order to enhance the economic feasibility of small power production facilities." However, long-term contracts, as defined by current electric utility practice, are of shorter and shorter duration. Duke explained that in Docket No. E-100, Sub 41A, the Commission recognized that, while long-term levelized rates are advantageous to QF developers, they pose a greater risk to ratepayers because they require greater overpayments during the early part of the contract period and they are necessarily more difficult to forecast accurately. Duke pointed out that in Docket No. E-100, Sub 79, the Commission eliminated the 10-year and 15-year levelized fixed-rate options for all QFs other than hydroelectric QFs and waste-fueled QFs. Various utilities, including Duke, argued for elimination or further limitation of the requirement to offer 10-year and 15-year options in subsequent avoided cost proceedings; however, the Commission continued the requirement to offer 10-year and 15-year rates to hydroelectric QFs and waste-fueled QFs.

Owners and developers of hydroelectric and waste-fueled QFs desire long-term contracts and long-term fixed rates in order to assist them in obtaining financing for projects. Duke argued that it is not reasonable to require utilities to perpetually offer 10-year or 15-year levelized rates to QFs and proposed a compromise position between this risk and the certainty of pricing that QFs seek, i.e. offering 10-year and 15-year levelized fixed rates to new projects and 5-year term contracts for subsequent renewals. In its Initial Statement, Duke noted that of the sixteen projects currently selling power to Duke in North Carolina, fifteen are served under standard or negotiated long-term contracts with terms greater than five years. Five of these projects are already under a second consecutive 15-year contract. Since these sixteen projects are already viable and operating, long-term rates of 10- and 15-year terms are no longer needed to support initial project startup costs and to obtain project financing. Duke argued that a suitable balance between the desirability of long-term contracts to encourage the development of QF projects and the risks of uncertainty of future capacity and energy costs borne by the utility and its customers is to limit the availability of 10- and 15-year levelized fixed-rate options to new hydroelectric and waste-fueled QF projects. Additionally, continuing to offer these options for new QF projects will provide support to the development of projects that may be eligible for credits from the NC GreenPower program.

Dominion's Position

According to Dominion, long-term levelized rates are permitted, but not required, by the regulations implementing Section 210 of PURPA. Long-term contracts are encouraged in order to enhance the feasibility of small power production facilities by G.S. 62-156(b)(1). Dominion's proposal includes 5-year, 10-year, and 15-year levelized rates, and is consistent with the Commission's Order in E-100, Sub 96. The longer-term, levelized rate options are available only to very small QFs, using energy sources that State policy explicitly encourages.

NCSEA's Position

In its Initial Comments, NCSEA strongly objected to PEC's proposal to limit long-term CSP rates to exclude wind and non-animal waste forms of biomass. (As noted above, PEC now proposes to expand the types of QFs eligible for the standard rates to include solar power, wind generators and generators using non-animal waste forms of biomass.)

Public Staff's Position

The Public Staff also noted that whether the Commission should require the electric utilities to offer long-term levelized rates to any QF as standard rate options has been an issue in prior avoided cost proceedings. In addition, a new issue has been raised in this proceeding: PEC has proposed adding solar, wind, and non-animal forms of biomass to the types of QFs that are entitled to the long-term levelized standard contracts.

The Public Staff stated that Duke and the other utilities have routinely proposed eliminating 10- and 15-year levelized rate contracts, and those proposals have been rejected by the Commission. Duke does not offer anything new in support of its current, more limited proposal. The hydro QF owners and operators in the State believe that the need for long-term contracts still exists. They have consistently indicated that they would be unable to obtain bank financing for capital expenditures for repair and maintenance in the absence of contracts ensuring that there will be a long-term market for their power. The Public Staff recommended that the Commission reject Duke's proposal. Avoided cost rates are much lower today than they were in the early years of PURPA; consequently, the danger that long-term rates may impose large stranded costs on utilities has been greatly reduced. Moreover, elimination of the longer-term contracts could result in significant harm to the already struggling hydro operators. It is significant that these longer-term, levelized rate options are available only to very small QFs using energy sources that State policy explicitly encourages.

The Public Staff observed that PEC proposes to eliminate the availability of the 10- and 15-year long-term capacity credits to QFs with a contract capacity of 3 MW or less and to limit such credits to QFs of 100 kW or less. The Public Staff objected to this proposal, pointing out that Dominion made similar proposals in the 1998 and 2000 avoided cost proceedings, and the Commission declined to adopt them. Instead, the Commission directed Dominion, as well as the other electric utilities, to offer 5-year levelized rates to all QFs contracting to sell 3 MW or less capacity. The Public Staff argued that PEC has not presented any valid reason that would justify departing from the position taken in the 1998 and 2000 orders. 18 C.F.R. 292.304(c)(2) specifically states that "there may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts," and this Commission has traditionally chosen to make standard rates available to a larger number of QFs than the minimum required by the FERC regulations. The Commission's position on this issue also furthers the State policy enunciated in G.S. 62-156.

The Public Staff noted that prior to the 1984 avoided cost proceedings in Docket No. E-100, Sub 41A, PEC and Duke were required to offer long-term levelized rate options to all QFs, and Dominion was required to offer such options only to small power producers as defined in G.S. 62-3(27a). In the 1984 proceeding, however, both the Public Staff and the utilities raised concerns about these options, and the Commission undertook a re-examination of the issue. The Commission sought a balance between the policy of encouraging QF development, especially the development of small power production under G.S. 62-156, and the risks posed by defaults and the uncertainty of the projections on which long-term rates are based. The Commission resolved these concerns by requiring PEC, Duke and Dominion to offer long-term levelized rates for 5-, 10-, and 15-year periods as standard options to hydroelectric QFs of 80 MW or less capacity and to non-hydro QFs contracting to sell 5 MW or less capacity. Non-hydro QFs contracting to sell capacities of more than 5 MW were given the options of contracts at the variable rates set by the Commission or contracts negotiated with the utility.

The Public Staff pointed out that the Commission continued this basic framework of long-term levelized rate options through several biennial proceedings with two changes. The first change began with the 1988 proceedings in Docket No. E-100, Sub 57. In that proceeding, Dominion was allowed to change from a long-term levelized energy payment to energy payments based on a long-term levelized generation mix with adjustable fuel prices. (Dominion was required to offer a long-term levelized energy payment as an additional option for small QFs of 100 kW or less.) The second change came about in 1988 for Dominion and in 1994 for Duke as a result of their pursuit of competitive bidding. In its final order in Docket No. E-100, Sub 74, the Commission concluded that a utility could refuse to negotiate individually with a QF when the utility is planning to pursue competitive bidding for its next block of capacity needs and the QF is seeking to sell both energy and capacity. Because both Dominion and Duke had active competitive bidding processes underway, the Commission concluded that QFs desiring to sell capacity to either of them should participate in their competitive bidding processes. The Commission noted that QFs offering to sell greater than 5 MW of capacity to Duke and Dominion were still eligible to sell energy only at the approved variable rates without participating in a competitive bidding process. Because PEC, at that time, was not pursuing a competitive bidding process, the requirement was continued that QFs larger than 5 MW desiring to sell energy and/or capacity should have the option of the variable rates or negotiated contracts. The exact point at which a utility could invoke a refusal to negotiate with a larger QF was left to be resolved by the filing of a motion with, and the receipt of an order granting it, from the Commission, which PEC pursued in 1996.

The Public Staff observed that, in the 1996 proceeding in Docket No. E-100, Sub 79, PEC, Duke, and Dominion proposed eliminating the 10- and 15-year levelized rate options from the standard rates available to QFs. PEC and the Public Staff entered into a compromise under which 5-, 10-, and 15-year levelized rates would be made available only to hydro QFs of 5 MW or less capacity and to QFs of 5 MW or less capacity fueled by trash or methane from landfills or hog waste. They also agreed that PEC would offer 5-year levelized rates to all other QFs with 3 MW or less capacity. The Commission ordered that all three utilities had to make available 5-, 10-, and 15-year levelized rates to hydro QFs contracting to sell 5 MW or less and to QFs contracting to sell 5 MW or less fueled by trash or methane from landfills or hog waste. The Commission's Order further provided that PEC, Duke and Dominion should offer 5-year levelized rates to all other QFs contracting to sell 3 MW or less, 5 MW or less, and 100 kW or less, respectively.

In the 1998 proceedings in Docket No. E-100, Sub 81, Duke and Dominion again proposed eliminating the 10- and 15-year levelized rate options from their standard rates available to hydro QFs of 5 MW or less capacity and to QFs of 5 MW or less capacity fueled by trash or methane from landfills or hog waste. The Public Staff and the QFs opposed this proposal, and the Commission rejected it. In order to provide for uniform treatment of non-hydro QFs other than those fueled by trash or methane from landfills or hog waste, the Commission ordered that PEC, Duke and Dominion all make 5-year levelized rates available to QFs of all types contracting to sell 3 MW or less.

The Public Staff stated that, in the 2000 proceeding, Docket No. E-100, Sub 87, PEC, Duke and Dominion once again proposed that the 10- and 15-year levelized rate options be eliminated, arguing that the standard long-term projections of costs are inherently unreliable. The utilities further noted that 10- and 15-year levelized rates are not specifically required by either state or federal law. The Public Staff and a QF intervenor strongly opposed the utilities' proposal. They contended that the 10- and 15-year rate options were required by this Commission to encourage the development of associated methane gas.

In the 2002 proceedings in Docket No. E-100, Sub 96, Duke and Dominion again proposed, and the Public Staff and QFs again opposed the elimination of the 10- and 15-year rate options. The Commission again rejected the proposals.

<u>Commission Conclusion</u>

This is an issue that the Commission must continually reconsider as economic circumstances change from one biennial proceeding to the next. In doing so, the Commission must balance the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. The increasingly competitive nature of the utility industry makes the latter considerations more compelling today than in the past. However, the Commission continues to believe that its decisions in the most recent avoided cost proceedings strike an appropriate balance between these concerns. The Commission therefore concludes that PEC, Duke, and Dominion should each continue to offer long-term levelized rate options of 5-, 10-, and 15-year terms to hydro QFs contracting to sell 5 MW or less and to QFs contracting to sell 5 MW or less that are fueled by trash or methane from landfills or hog waste or poultry waste and that they should offer 5-year levelized rates to all other QFs contracting to sell 3 MW or less. With these limitations, long-term contract options serve important statewide policy interests while reducing the utilities' exposure to overpayments. The policy interests to be served include those stated in G.S. 62-156(b)(1), which specifically provides that long-term contracts "shall be encouraged in order to enhance the economic feasibility of small power production facilities." This is a State policy, and it supports a decision to require long-term rate options for hydro QFs. We believe that the State policy of reducing and managing solid waste landfills set forth in G.S. 130A-309.01 to -309.29 supports extending these options to facilities fueled by trash or methane from landfills. Although there is no specific statute dealing with hog waste or poultry waste, the Commission nonetheless believes that there is an environmental policy to be served by encouraging facilities fueled by methane from hog or poultry waste. While the Commission believes that these policies should be furthered, it is also concerned about reducing the utilities' exposure to overpayments, and our decision accomplishes this as well. The facilities entitled to long-term rates are generally of limited number and size. Few new hydro facilities are being certificated; most sites are already developed. The number of trash and methane sites large enough to support generation also appears to be limited. Although G.S. 62-156(b)(1) applies to hydros of 80 MW or less, there are few large hydro sites available in North Carolina, and the Commission has limited long-term rates to hydros contracting to sell 5 MW or less in order to further reduce the exposure inherent in rates based on long-term forecasts of the utilities' costs.

The Commission concurs with PEC, NCSEA, and the Public Staff that it is in the public interest to encourage the development of QF generation fueled by solar, wind and non-animal waste biomass, and therefore, approves their proposal to expand the eligibility for the standard rates to include solar, wind and non-animal biomass. This expansion of the list of eligible generators shall apply to PEC, Duke and Dominion.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 4

PEC's Position

PEC believes that it is appropriate to offer its variable capacity and energy rates and standard long-term 5-year, 10-year, and 15-year levelized rates to hydroelectric, solar, wind, waste and biomass fueled QFs with a contract capacity of 5 MW or less and other QFs with a contract capacity of 100 kW or less. It is appropriate to require all QFs not eligible for the standard long-term levelized rates to negotiate purchase power arrangements with PEC.

PEC noted that, in its Order in Docket No. E-100, Sub 41A, the Commission found that QFs of 5 MW or larger have such substance as to have the resources and expertise to negotiate with utilities and that the competing interests of the parties can best be resolved by negotiations. The Commission further explained that one of the primary reasons for requiring large QFs to negotiate rates was the large financial risk a utility and its retail customers are exposed to when a utility signs a long-term purchased power agreement at fixed avoided cost rates based on long-term cost forecasts, given the uncertainty involved in forecasting a utility's avoided cost. If a utility overestimates its avoided costs, the utility and its customers are forced to pay higher costs for electricity than would otherwise be the case for up to 15 years. PEC asserted that the

Commission's primary duty is to ensure retail utility customers are furnished electricity at the lowest reasonable cost. Unnecessarily exposing retail customers to the risk of overpayment does not serve that goal.

In addition, as explained by PEC in its Reply Comments, a utility must maintain the ability to negotiate all aspects of contracts with larger QFs because their operational flexibility and size may negatively impact system operations. Any change affecting the economic operation of a utility system caused by a QF indiscriminately providing energy into the utility's system results in costs to that utility that would have not otherwise been incurred. As a result, the utility must maintain the option of controlling deliveries from the QF to not only prevent incurring additional costs, but to preserve system reliability.

According to PEC, in the past, as in this case, certain large QFs not eligible for the standard long-term rates have asserted that the utilities have greater bargaining power than the QFs and that the utilities have, at times, used this greater power to negotiate in bad faith. Beginning in Docket No. E-100, Sub 53, the Commission explained that the proper remedy in this situation is for such a QF to file a complaint with the Commission against the utility in question. In addition, in the Commission's most recent avoided cost proceeding, Docket No. E-100, Sub 96, the Commission established an arbitration process for those QFs that believe they are being treated unfairly by a utility.

PEC stated that, in addition, in Docket Nos. E-100, Sub 74, and E-7, Sub 545, the Commission found that generators not directly connected to a utility are not entitled to a utility's standard avoided cost rates. The Commission further found that it must consider factors such as the availability of a QF, the reliability of a QF, the value of the QF power to a utility, and the utility's alternative power sources in determining the avoided cost rates to be paid to a QF with which the purchasing utility is not directly connected. The Commission then concluded that purchasing power from such QFs causes a utility to incur costs that are not present when a utility purchases power from an interconnected facility and that these costs are not reflected in a utility's avoided cost rates.

CCWE's Position

In its Initial Comments, CCWE asked the Commission to reconsider its approval of the peaker method for fixing PEC's avoided cost rates and instead require that those rates be set based upon the actual costs associated with the next proposed generation unit or long-term purchased power contract reflected in PEC's Least Cost Integrated Resource Plan. CCWE argued that PEC should then be required to revise the proposed terms of CSP-22 to set standard variable capacity and energy rates that would be available for all existing QFs willing to commit to a standard term of four to five years. CCWE believes that the current method of fixing avoided cost rates sends illogical and uneconomic price signals to QFs generally and, due to the inequality in bargaining power between a utility and larger QFs such as CCWE, allows PEC to pay larger QFs a lower amount per kwh than smaller QFs, even when the larger QF offers a product that is more reliable, more often available, and often is dispatchable.

CCWE offered that one signal that the present combination of PEC's tariff structure and the peaker method for determining avoided costs merits reconsideration is that it produces anomalous results that ignore or, at minimum, discount the implementing regulations of the FERC concerning the determination of avoided costs. By relying on negotiations for larger QFs, while requiring standard terms for smaller QFs, the current approach in North Carolina effectively leads to higher capacity payments to smaller QFs than to larger QFs, without regard to the relative reliability, availability, and dispatchability of the generation facilities.

CCWE argued that standard avoided cost rates for capacity and energy should be available for purchases from QFs which do not qualify for the standard terms and conditions due to the fuel used or the size of the QF, because all QFs, regardless of size or fuel type, are entitled under PURPA to rates based on the full avoided costs of the purchasing utility, unless the QF and utility agree to rates above or below the full avoided costs of the affected utility. In this regard, because the output of larger QFs tend to be available during more hours, with greater reliability, and often in a mode which can be dispatched, no reasonable basis normally will exist for paying such QFs less than the standard rates for capacity and energy which are offered to smaller QFs with facilities that are less available, less reliable, must-run facilities.

CCWE noted that the treatment of QFs not qualifying for the long-term, levelized rate options due to size and/or fuel type has been one of the principal points of dispute in several proceedings, and it continued to be a subject of dispute in this proceeding. Most of the QFs affected by this issue are located within the PEC control area and are physically interconnected to the transmission system owned and operated by PEC.

According to CCWE, participation in a bidding process has not been a meaningful option for QFs interconnected to the PEC transmission system because there have not been any significant requests for proposals for additional capacity issued by PEC during the last several years. CCWE argued that PEC has not demonstrated in this proceeding that the use of a bidding procedure occurs with sufficient frequency to meaningfully affect the use or development of QF generation in this State. As a result, as a practical matter, larger QFs will have to continue to rely on negotiations to reach agreement on the terms and conditions of a contract relating to the capacity and energy made available to PEC by a larger QF.

CCWE urged the Commission to establish standard rates for capacity and energy for larger QFs which are equal to the rates offered to smaller QFs for contracts of comparable duration and deliveries. Such rates for larger QFs would be based on the avoided costs PEC has used to develop the standard rates offered to smaller QFs. CCWE also requested that the Commission establish terms and conditions for the sale of energy and capacity by larger QFs. In this regard, CCWE noted that the tariff structure for QF purchases used in the past by PEC, and proposed to be used by PEC in the future, sends an incorrect pricing signal which discriminates against larger QFs. Specifically, because the generation resources of larger QFs typically are available during more hours, are more reliable, and more often can be dispatched as needed, under traditional industry standards and FERC regulations, there is rarely a reasonable basis for paying less for such types of capacity than is paid for the less available, less reliable, must-run resources of smaller QFs.

CCWE emphasized that the obligations of utilities under PURPA to allow the interconnection of QFs, to sell power to QFs, and to purchase the output of QFs, were imposed as a matter of law precisely because utilities have both the economic incentive and the market power to reduce competition by simply refusing to deal with these types of generators, or by using delay to create economic pressure to accept whatever terms and conditions a utility may dictate. In short, reliance primarily on negotiations to produce reasonable and non-discriminatory rates for QF purchases implicitly assumes an equality of bargaining power between the QF and the purchasing utility, despite the fact that it was the inequality of bargaining power that prompted the mandatory obligations of PURPA in the first instance. After all, the mandatory obligations of PURPA would not have been necessary if the utilities had lacked the market power to delay or exclude such generation by simply refusing to deal. Indeed, CCWE emphasized that, in establishing its implementing regulations, FERC expressly noted the decision to extend to a QF the option of requiring a utility to enter into a "legally enforceable obligation" was intended to prevent a utility from circumventing the requirement of a capacity credit for an eligible QF facility by merely refusing to enter into a contract with the QF.

CCWE stated that the FERC regulations, specifically 18 C.F.R. 292.304(a) through (e), require the following: (1) rates for purchases from QFs are to be just and reasonable to the electric consumer, in the public interest, non-discriminatory against QFs, and required to be, equal to, but not greater than, the full avoided costs and (2) capacity rates for purchase from QFs are compliant with PURPA if the capacity rates equal the utility's full avoided costs, which are to be determined after consideration of various factors (listed in 18 C.F.R. 292.304(e)) which affect the usefulness of a resource in the least-cost operation of a system. CCWE noted that no party has advocated in this proceeding that the Commission establish avoided cost rates in excess of the amount determined by the Commission to be the involved utility's full avoided costs.

CCWE asserted that the establishment of standard rates, terms and conditions for QFs in excess of 5 MW is consistent with the purposes and language of PURPA and its implementing regulations, and also will further the public interest by establishing a baseline from which these QFs and the utilities can negotiate any alternative arrangements to which both parties agree. CCWE stated that the steadfast opposition of PEC to standard rates, terms and conditions for QFs generally, and larger QFs in particular, is clear. While voluntarily negotiated contracts offer many advantages over mandatory contracts in some instances, the Commission cannot overlook that mandatory obligations on utilities are the focus of both PURPA and its implementing regulations, and such mandatory obligations were necessary precisely because negotiations may not lead to fair or reasonable terms and conditions for QFs.

In this regard, CCWE commented that negotiated rates for larger QFs may be accepted for business reasons even when unreasonably low rates are offered by the purchasing utility in order to avoid the costs of lengthy disputes and to avoid interruptions in the payments by the utility under contracts for previous periods that have expired. As a result, an undue reliance solely on negotiated rates for larger QFs likely would lead to a downward "ratchet effect," where the negotiated rates of a larger QF that are below the utility's full avoided costs are used in subsequent negotiations with other QFs to justify even lower rates for additional QF capacity and energy, without regard to the actual avoided costs of the purchasing utility. CCWE concluded that through time, the predictable consequence would be to lower the capacity and energy credits for a larger QF below the full avoided costs of the purchasing utility.

According to CCWE, the requirement of the payment of full avoided costs to owners of QF facilities reflects the long-standing result of FERC's balancing of the interests of ratepayers and the desire to encourage QF development. By making available to larger QFs the variable rates for energy and capacity, and standard terms and conditions for such sales, based on the rates established by the Commission using the avoided costs of PEC, retail consumers will not be harmed, and the national policy of encouraging the production of energy by cogenerators and small power producers will be furthered.

NCSEA's Position

NCSEA asked why avoided cost standard contracts are restricted only to projects of 3 or 5 MW. PURPA limits for renewable energy projects are much higher than current NC avoided cost standard contract limits. Biomass and wind projects in North Carolina will probably be much larger than the 3 to 5 MW projects for which standard rates are available. NCSEA concluded that avoided cost standard contracts need to be made available to these larger projects.

Public Staff's Position

The Public Staff stated that, in this biennial proceeding, the Commission has been presented with concerns about (1) the limited availability of standard contract rates and about the ability of QFs to adequately and successfully negotiate with utilities; (2) whether a methodology should be approved for calculating "as available" avoided energy rates that are based on costs that are closer to being "real time" than the variable energy rate; (3) whether the availability of such an "as available" rate would have any effect on a utility's ability to purchase power at prices lower than its avoided costs; and (4), assuming there are legitimate concerns about the availability of such an "as available" rate, what provisions would be necessary or appropriate to protect any market-sensitive information used to calculate such a rate.

The Public Staff's Reply Comments noted that, under PURPA, a larger QF is just as entitled to full avoided costs as a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules was never intended to suggest otherwise. A QF such as CCWE, which has achieved an availability factor of approximately 95 percent during the nearly 15 years it has been operating pursuant to a contract with PEC, obviously has value as capacity to PEC.

The Public Staff also noted that, in the last proceeding, the Commission ruled that, absent an approved, active solicitation, negotiations between a utility and a larger QF are subject to arbitration by the Commission at the request of either the utility or the QF to determine the utility's actual avoided cost, including both capacity and energy components, as appropriate, as long as the QF is willing to commit its capacity for a period of at least two years. Purportedly, such an arbitration would be less time consuming and expensive (and therefore less of a burden) on the QF than the previously available complaint process. It seems reasonable to suppose that a larger, reliable QF willing to make a 5-year commitment would be found to be entitled to avoided cost rates comparable to the 5-year levelized rates in the standard rate schedule. While the Public Staff recognized that arbitration by the Commission would continue to place the burden of pursuing a remedy upon the QF, it seems to the Public Staff to be the most reasonable solution given prior rulings by the Commission.

Commission Conclusion

The Commission concludes that PEC, Duke, and Dominion should continue to be required to offer QFs not eligible for the standard long-term levelized rates the option of contracts and rates derived by free and open negotiations with the utility or, when explicitly approved by Commission Order, participation in the utility's competitive bidding process for obtaining additional capacity. The QF also has the right to sell its energy on an "as available" basis pursuant to the methodology approved by the Commission. Under PURPA, a larger QF is just as entitled to full avoided costs as a smaller QF. The exclusion of larger QFs from the long-term levelized rates in the standard rate schedules was never intended to suggest otherwise.

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

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 5

PEC and Duke have used the peaker methodology to develop their avoided costs in each of the past several avoided cost proceedings; Dominion has used the DRR methodology.

According to the theory underlying the peaker method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant. This is because the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. Thus, the summation of the peaker capital costs plus the system marginal running costs will theoretically match the cost per kWh of a new baseload plant, assuming the system is operating at the optimum point. Stated simply, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.

The DRR methodology involves a comparison of the revenue requirements which result from two alternative system expansion plans, one including a block of new QF capacity and the other excluding such a block. The utility's generation costs are calculated on a yearly basis for an extended period of time for each of these two scenarios. The difference between the two scenarios is then computed for each year, and the results converted into present value terms, thereby providing an estimate of the present value of the total avoided cost of the assumed block of QF capacity.

In previous biennial proceedings, the Commission concluded that it should not require PEC, Duke, and Dominion to utilize a common methodology for calculating avoided costs. There are widely divergent options among even those who are expert in these matters as to what costs are actually avoided and what methodologies will best identify those costs. The peaker method and the DRR method are generally accepted and used throughout the electric utility industry. Dominion's comparison of the results of the peaker and DRR methodologies as applied to them in a previous proceeding showed very little difference between the methodologies.

The Commission also concluded in previous biennial proceedings that it should not require the utilities to adopt a specific generating unit or type of unit for calculating avoided costs. The Commission has consistently found in previous biennial proceedings that the avoided cost of a utility system is not necessarily unit specific. Addition or deletion of a given generating unit affects how the remaining generating units are run. The economics of a generation mix is usually determinative, not the economics of a single unit.

For the purposes of this proceeding, the Commission concludes that both the peaker method and the DRR method are still generally accepted and used throughout the electric utility industry and are reasonable for use in this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6-7

Duke's Position

Duke took the position that a performance adjustment factor (PAF) of 1.0832 is an appropriate adjustment to Duke's avoided capacity cost and should be utilized by Duke for its avoided capacity cost calculations for all QFs. Under PURPA, QFs are entitled to a capacity payment equal to the value of the capacity the utility may avoid. Duke proposes use of a PAF that increases the avoided capacity cost rates paid to QFs by applying a multiplier to the annual cost of capacity that Duke would otherwise use to meet its customer peak demand. This PAF-adjusted annual capacity cost reflects the value of avoided capacity as if it were 100% available. Duke argued that it is appropriate to use the availability of a combustion turbine in the calculation of the PAF.

Duke presented evidence that combustion turbine scheduled maintenance outage times and forced outage rates have improved over the years to the point that the combustion turbine capacity resource used as the basis for this capacity calculation is projected to have an average annual availability of 92.32%, with an overall forced outage rate of 5.37%. This availability factor includes 560 hours of scheduled outage time (affecting 134 on-peak hours) during the non-summer months. Duke proposes to use this availability factor in calculating a PAF of 1.0832 in this proceeding for all QFs (where 1.0832 = 1 ÷ 0.9232).

Duke argued that even though its avoided capacity costs prior to 2010 are avoided market capacity purchases, Duke's contracts for capacity in those years reflect combustion turbine capacity and thus it is appropriate to use a combustion turbine based availability factor for all years of the capacity credit calculation.

Since the proceedings in Docket No. E-100, Sub 79, the Commission has required Duke to adopt a PAF of 2.0 for the avoided capacity cost calculations for hydro QFs not in excess of 5 MW with no storage capability (run-of-the-river hydro QFs) and a PAF of 1.20 for all other QFs. Duke continues to disagree with this requirement. In particular, the requirement of a PAF of 2.00 results in substantially higher rates for run-of-the-river hydro QFs than other QFs and is inconsistent with PURPA and with competitive wholesale generation industry practices. Duke argued that its application of the PAF of 1.0832 appropriately recognizes the availability factor of the avoided unit. Duke argued that to pay higher avoided cost rates through the use of a higher PAF adjustment results in capacity rates exceeding the avoided cost of capacity, contrary to PURPA and G.S. 62-156.

Duke disagreed with the Public Staff's characterization of the PAF as a mechanism to adjust avoided capacity cost rates to accommodate the operating characteristics of certain QFs. Duke noted that under the methodology proposed by the Public Staff, Duke's Schedule PP rates would pay run-of-the-river hydro QFs 18.27 cents for each kWh delivered during summer on-peak hours, more than three times the current market value of this energy, and more than twice the retail value of this energy if sold to one of Duke's residential customers. Instead, to address the issue of limited operational hours of run-of-the-river hydro QFs, Duke proposes the use of its

"Option B" set of on-peak and off-peak hours that enables these QFs to earn a full capacity credit while operating over shorter on-peak operating hours, thus eliminating the need for a higher PAF for these facilities. This proposal is consistent with the approach taken by the Georgia Commission.

Duke noted that the calculation of capacity payments under typical wholesale power purchase agreements is based upon the total firm capacity the seller can generate at the time of the utility's peak demand. Further, in the wholesale market, capacity contracts paid on a $/kW basis typically have substantial performance penalties for failure to deliver energy when called upon, such as loss of capacity payments, replacement power costs and contract termination. The use of a 2.0 PAF in calculating avoided cost rates for run-of-the-river hydro QFs bears little resemblance to practices in the wholesale market. These QFs often provide limited capacity value during the on-peak hours, which occur during the hot, dry summer months.

Duke argued that it only avoids capacity additions by purchasing from a QF to the extent the QF can deliver the capacity when Duke needs it — during peak times. Duke's proposed capacity rates utilizing a PAF of 1.0832 appropriately and fully compensates the QF for capacity that the QF actually provides and Duke avoids. In fact, the QF is paid 108% of Duke's cost of capacity for every kW the QF delivers to Duke. Instead, the 2.0 PAF for run-of-the-river hydro QFs improperly compensates such QFs for capacity that it does not enable Duke to avoid. Duke noted that NCSEA's proposal to develop PAFs for energy technologies with availability factors of 20% and 30% would further exacerbate this inconsistency and highlights the need to dispel the misperception that the purpose of PURPA is to subsidize the development of such energy resources. Avoided cost rates are not intended to be based upon the capacity that a QF can deliver, but upon the capacity the utility can avoid.

Duke stated that CCWE argued that "the current approach in North Carolina effectively leads to higher capacity payments to smaller QFs than to larger QFs, without regard to the relative reliability, availability and dispatchability of the generation facilities." CCWE stated that it has achieved an availability factor of approximately 95%, however, the capacity rates it receives are "substantially less than the rates offered small hydroelectric QFs with availability factors of half that amount." The problem, according to Duke, is the result of small QFs, particularly run-of-the-river hydro QFs, being overcompensated through use of an artificially high PAF.

Duke noted that the Public Staff continues to argue that run-of-the-river hydro QFs are entitled to preferential treatment because "these facilities are environmentally friendly, and N.C. 62-156 reflects a State policy encouraging their use." Such arguments are not a justification for preferential treatment. During a Dominion rate proceeding some years ago, the Commission found that the Virginia Commission had improperly considered "intangible environmental and societal benefits," including the economic health of the local community, in ordering the utility to enter into contracts with QFs at rates above the bids it received under a competitive solicitation. In that proceeding the Public Staff advocated for the disallowance of expenses attributable to capacity payments to these QFs.

Duke further observed that the California Commission adopted an adjustment similar to the PAF in calculating avoided cost rates that had the analogous effect of providing a subsidy to certain QFs. In calculating transmission line losses, the California Commission adopted a floor transmission loss factor (TLF) of .95 for QFs relying on renewable resources for their fuel source. In support of this ruling, the California Commission stated, "We find that the societal benefits associated with resource diversity and the environmentally-preferred energy production offered by renewable resources merits special treatment for renewable QFs." On appeal, it was held that the use of the .95 TLF resulted in rates that did not represent actual avoided cost and therefore violated PURPA. The California Commission's rationale for use of this factor was found to be impermissible because it forced consumers to subsidize certain QFs.

Duke emphasized that G.S. 62-156 expressly states that "the rates paid to a small power producer shall not exceed the incremental cost to the electric utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source." Therefore, Duke argued that this statute cannot provide a basis for requiring that utilities pay run-of-the-river hydro QFs capacity rates in excess of avoided cost. Duke noted that a more appropriate means of providing subsidies to such facilities is through programs such as the NC GreenPower program, through which consumers elect to make contributions that support and encourage the development and use of these facilities.

NCSEA's Position

NCSEA raised the issue as to whether a different PAF should be used for other technologies in addition to hydroelectric generation. NCSEA offered that renewable technologies have different, well-established availability factors. For example, NCSEA stated that solar and wind would be expected to be available 20% to 30% of the time. NCSEA asserted that capacity payments should take these availability levels into account.

Public Staff's Position

The Public Staff stated that a PAF of 1.2 should be utilized by both PEC and Duke for their respective avoided cost calculations for all QFs in this proceeding, except hydro facilities with no storage capability and no other type of generation. A PAF of 2.0 should be utilized by both PEC and Duke for their respective avoided cost calculations for hydro facilities with no storage capability and no other type of generation. Whether a different PAF should be used for solar and wind technologies should be addressed in the next biennial proceeding.

The Public Staff observed that Duke has challenged the PAF of 1.2 in virtually every proceeding since it was established. It once again contends that the Commission should adopt a lower PAF. This time the recommended PAF is 1.0832, which is even lower than the PAF of 1.129 proposed in the last proceeding. This factor would allow a QF to receive its full capacity payment only if it operated 92.32 percent of the time, which Duke asserts is closer to the actual availability of its CTs. The Commission has consistently rejected Duke's arguments and continued the use of the PAF of 1.2. As the Commission has noted in previous proceedings, under the peaker methodology marginal capacity costs are based upon the supply-side resource with the lowest investment costs for providing peak capacity (without offsetting energy savings), which is usually a CT. Therefore, the costs of a CT are a proxy for a utility's generic "pure" cost of capacity and form the basis for rates that apply to every type of QF. Thus, according to the Public Staff, there is no logical justification for basing the PAF on the expected outage rate of a CT. The use of a 1.2 PAF requires a QF to operate 83% of the time in order to collect its entire capacity credit, which is reasonable.

The Public Staff argued that the Commission's use of a 2.0 PAF for hydro QFs with no storage capacity or additional fuel source also is appropriate and should be continued in this case. The output of a run-of-the-river hydro facility is dependent on rainfall and cannot be controlled by the plant operator. The evidence offered in the proceeding in which the 2.0 PAF was adopted showed that the utilities operated their hydro plants at lower capacity factors and that a higher PAF was therefore justified. A 2.0 PAF gives run-of-the-river hydros a more reasonable opportunity to receive their full capacity payments. Moreover, these facilities are environmentally friendly, and G.S. 62-156 reflects a State policy encouraging their use. The Public Staff argued that the Commission should not adopt a PAF that could detrimentally affect the industry by making it virtually impossible for hydro QFs to collect rates equal to the utility's full avoided costs.

Commission Conclusion

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

The Commission has carefully reviewed all of the comments on this issue and concludes that a PAF of 1.2 should continue to be used by PEC and Duke in determining the avoided capacity cost rates for all QFs (including solar and wind) other than hydro facilities with no storage capability and no other type of generation. While the peaker methodology employed by PEC and Duke relies on the cost of a combustion turbine to provide the purest estimate of avoided capacity costs, the fixed costs of a peaking unit represent a proxy for the capacity related portion of the fixed costs for any avoided generating unit. Thus, the availability of a CT is not determinative for purposes of calculating a PAF.

The Commission also concludes that a PAF of 2.0 should continue to be utilized by PEC and Duke in determining the avoided capacity cost rates for hydro facilities with no storage capability and no other type of generation. The Commission rejects Duke's assertion that a higher PAF for certain QFs is inconsistent with PURPA and competitive wholesale generation industry practices. These run-of-river hydro QFs are unique since their ability to generate is beyond the control of their operators because their fuel is essentially stream flow, which is influenced by rainfall. The use of a higher PAF for these hydro facilities does not result in rates that exceed avoided costs. It merely allows these QFs to receive the full capacity payments to which they are entitled by operating within the constraints of their stream flows, which is appropriate and reasonable.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 8

Duke's Position

According to Duke, a utility should not be obligated to make capacity payments to QFs larger than 5 MW if the utility does not have a need for capacity. In calculating its avoided capacity credits, Duke initially included a capacity value of $0 for the years 2005 and 2006 because it was not projecting incremental capacity needs for these years; however, based upon preliminary analysis for Duke's 2005 Annual Plan, Duke now has determined that it may have a need for some capacity in 2005 and 2006. Therefore, Duke will recalculate and file avoided capacity credits that include a value for capacity in 2005 and 2006 based upon the market capacity costs used in Duke's initial calculation to value capacity in years 2007 through 2010.

Duke argued that decisions by both this Commission and FERC make clear that utilities do not have an obligation to make capacity payments to QFs when the utility does not have a need for capacity. The principal FERC case for this proposition is City of Ketchikan, Alaska, Copper Valley Electric Association, Inc., City of Petersburg, Alaska, City of Wrangell, Alaska, 94 FERC 61,293 (2001). Duke noted that, in implementing Section 210 of PURPA, the FERC made clear that an avoided cost rate need not include capacity costs (as distinct from energy costs) where a QF does not permit the purchasing utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility. According to Duke, the FERC commented,

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load.

Duke further commented that, in the last biennial proceeding, this Commission recognized that QFs may be entitled to only energy payments when no capacity is avoided. On several occasions, the Commission has specifically approved avoided cost rates that included zero or discounted values for capacity given that the utility had little or no need for capacity. In Docket No. E-100, Sub 74, the Commission concluded that Carolina Power & Light should be allowed to discount its capacity costs for 1995 through 1997 because it did not have a need for capacity until 1998, and that Dominion should not be required to offer capacity credits to QFs prior to 1999 because it did not need capacity until that date. Duke stated that the Commission affirmed this approach in Docket No. E-100, Sub 81.

Duke stated that avoided cost capacity rates should be based upon the lowest cost capacity available to the utilities. Duke argued that it appropriately utilized market information regarding the cost of peaking capacity available to Duke on the wholesale market in the calculation of avoided capacity rates.

According to Duke, it has demonstrated in this case that its lowest cost of acquiring purchased power is through purchased power agreements through the year 2010. In its Initial Statement, Duke stated that, in recent years, Duke has identified the need for additional peaking capacity and has issued requests for proposals (RFPs) to determine whether it is in the best interests of Duke and its customers to build or buy that capacity. As recently as 2003, Duke issued an RFP and received twenty-nine proposals from twenty-six respondents for supplying capacity from the wholesale marketplace. Duke subsequently entered into four purchased power contracts for capacity for the 2007 to 2010 timeframe, the results of which provide peaking capacity during that time from combustion turbines at prices less than one-half of the cost of building new combustion turbine peaking capacity. Additionally, in its Reply Comments, Duke illustrated that capacity is still available to Duke in the market at very favorable prices for the period 2005 to 2010. Since it filed its proposed avoided cost capacity credits, Duke has received capacity offers at prices equal to or lower than the costs that Duke used in the development of its avoided cost rates in this case. Duke argued that the best estimate of avoided capacity cost in the 2007 to 2010 timeframe is the capacity costs associated with these purchases.

Consistent with this market information, Duke's proposed capacity credits for both the variable and fixed long-term rates are based on recent contracts that Duke has entered into to purchase capacity for the period 2005 to 2010, and the avoided cost of a new combustion turbine for the year 2011 and beyond. Although the Commission denied this approach in the last biennial avoided cost proceeding, in this proceeding Duke emphasized that the low capacity prices available in the market in 2002 have continued and in fact are available from a variety of resources through 2010. Therefore, given that Duke has continued to receive peaking capacity offers at prices below the cost of construction of a combustion turbine over the last two avoided cost proceedings, Duke concludes that market data produce rates that are representative of the true cost of capacity.

The Public Staff made an issue of the fact that Duke has only signed four purchase agreements for this period, as if signing more contracts would be a better indication of a market. Contrary to this point, Duke stated that while it has only needed to negotiate four agreements over this period to meet its additional peaking needs, capacity is still available to it in the market at very favorable prices for the period 2005 to 2010.

When Duke needs capacity, it examines self-build and purchase options to determine the most cost-effective acquisition for customers. Duke stated that its use of actual purchased capacity market data through the year 2010 is necessary and appropriate under PURPA because purchased capacity is lower in cost than the construction of new combustion turbine capacity during that time period. The PURPA regulations define "avoided cost" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." Duke's avoided capacity costs should reflect the availability of low-cost purchased capacity contracts. Basing avoided capacity cost rates solely on the cost of a combustion turbine when lower cost capacity purchases are available would result in Duke Power paying QFs greater than avoided costs in violation of PURPA regulations to the ultimate detriment of North Carolina consumers. In order to accurately reflect the true avoided costs as required by PURPA regulations, avoided cost rates should be established based upon the avoided cost of capacity, and that cost should include purchased capacity if that is how the capacity need is to be met.

Further, Duke argued that its approach is entirely consistent with the peaker methodology. As recognized by the Commission in Docket No. E-100, Sub 74, the peaker method of determining avoided capacity costs does not dictate that the cost of peaking capacity be calculated using the cost of new combustion turbine construction. Rather, the peaker method should represent the lowest cost of acquiring peaking capacity, which in the current case is through purchased power contracts through the year 2010. Duke's application of the peaker methodology in this docket is consistent with views of the National Economic Research Associates, Inc. (NERA) from as far back as 1987. In explaining the development of capacity costs under the component or peaker method, NERA's Dr. Parmesano stated:

> Avoided capacity costs are estimated by determining, for each year, the least-cost capacity option available to the utility. The least-cost option is often a peaking unit or a capacity purchase, but may also be a load management program, a base- load plant net of fuel savings it provides in nonpeak hours, or any other resource which could provide low-cost capacity in peak hours. In the early years of the period the utility may have sufficient capacity to meet projected loads. In these years avoided capacity costs are zero.

As in the 2002 biennial avoided cost proceeding, the Public Staff recommended that "avoided capacity costs for Duke continue to be based on actual investment costs that would be avoided because of the existence of a QF, rather than on a capacity market that is not functioning acceptably at this time." According to Duke, this recommendation supports Duke's use of actual market costs for capacity established in the Duke-PEC Ventures and Dynegy agreements. The capacity costs in these agreements represent Duke's "actual investment cost" to acquire capacity and serves as a proper basis for determining avoided capacity cost rates. Duke noted that in its Initial Comments, CCWE asserted that it believes use of long-term purchase contracts in the utility's least cost integrated resource plan would result in more accurate avoided capacity rates. Duke emphasized that this is precisely how Duke has calculated its avoided capacity credits for the years when such data is known.

<u>Public Staff's Position</u>

The Public Staff responded that because Duke was not, at least originally, projecting incremental capacity needs for 2005 and 2006, its calculation of avoided capacity rates reflects a capacity value of $0 for those two years. This has the effect of not only rendering the variable capacity credit zero for those years, but also of reducing the level of capacity credits substantially over the entire 15 years of Duke's analysis. The Public Staff objected to this proposal in its Initial Statement, arguing that it does not believe that the use of zeros is consistent with the peaker methodology and that the capacity rates that are produced if zeros are used do not reflect a utility's actual longer-term avoided capacity costs.

The Public Staff noted that a review of the utilities' filings in the integrated resource planning dockets reveals that a lack of need for incremental capacity in the near term is not atypical. A utility will usually have made arrangements for near-term capacity at least a year or two in advance, either by signing a purchase power contract or by beginning construction of a plant that is no longer avoidable. Because the peaker methodology uses the costs of a CT as a proxy for "pure" capacity costs, it would appear to be inappropriate to dilute those costs by inputting zeroes. The support offered by Duke shows only that the Commission in one proceeding allowed PEC to discount its near-term capacity costs. Unless a utility has significant excess capacity and little or no expected load growth out into the future, the Public Staff stated that it is inappropriate to input zeros into the calculation of avoided capacity rates that apply to periods in which capacity would need to be added.

The Public Staff further stated that it realized that some adjustment to the variable capacity rate might need to be made. However, because of the importance of small, distributed generation and the NC GreenPower Program, the Commission needs to be careful not to take action to their detriment. This issue needs to be more fully developed.

Duke has proposed using the capacity costs associated with several negotiated purchased power contracts as its avoided capacity costs for 2007 through 2010, as opposed to using the actual costs of building a CT. It made a similar proposal in the last proceeding that was rejected by the Commission. Duke maintained that, because it plans to purchase power from the market rather than building generation facilities, these market prices represent its marginal cost of capacity. Duke's rates are based on several recently re-negotiated wholesale purchase contracts. In its initial statement, the Public Staff questioned whether the use of market data as proposed by Duke would produce rates that are representative of the true cost of capacity.

The Public Staff argued that, first of all, market data are not available to estimate the price of capacity beyond five years into the future. Duke's application of the peaker method has assumed that, in years seven through fifteen, the market price of capacity would equate to the cost of a CT. In addition, the Public Staff is concerned that Duke's proposed capacity rate is based solely on four re-negotiated contracts. Even though Duke has conducted various RFPs, the end result was four purchase agreements with two entities that own existing CTs in a market that is considered overbuilt with supply. Naturally, the low prices observed in the wholesale marketplace are attracting relatively few investors and will limit capital for new generation. The fact that current prices are not adequate to attract new investment from utility owners suggests that these prices are too low for determining avoided costs. In addition, there currently is ongoing consideration of whether the market can provide capacity, as illustrated by the proposed revisions to the capacity construct of PJM Interconnection, LLC, and the FERC's on-going consideration of "reliability compensation" issues. An additional concern is that Duke is not relying solely on the market for its future resource needs. Finally, the Public Staff argued that Duke's proposed market approach is not entirely consistent with the peaker methodology, which Duke itself staunchly defended in prior proceedings.

The Public Staff stated that it believes that it is inappropriate to use the current low prices of capacity to determine avoided capacity rates that will be in effect for many years after the capacity glut has dissipated and wholesale electricity prices return to a higher level that reflects a more stable market. As shown previously, Duke is proposing to dramatically reduce its avoided cost rates. If the Commission rejects Duke's proposal and continues to support the policies approved in prior proceedings, the new avoided capacity rates will remain at a more reasonable level. Therefore, the Public Staff recommended that avoided capacity costs for Duke continue to be based on actual investment costs that would be avoided because of the existence of a QF, rather than on a capacity market that is not functioning acceptably at this time.

<u>Commission Conclusion</u>

The Commission notes that, based upon preliminary analysis for Duke's 2005 Annual Plan, Duke has now determined that it may have a need for some capacity in 2005 and 2006.

The Commission therefore directs Duke to recalculate and file avoided capacity credits that include a value for capacity in 2005 and 2006.

In addition, the Commission concludes that, for the reasons provided by the Public Staff, Duke's proposal to use market data to calculate avoided capacity costs should be rejected and that all avoided capacity costs should continue to be based on actual investment costs that would be avoided because of the existence of a QF. The Commission reached this same conclusion in the most recent avoided cost proceeding, where both Duke and Dominion unsuccessfully proposed the use of the market price of capacity in determining avoided cost rates.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 9

PEC's Position

According to PEC, it is premature and inappropriate for the Commission to address the question of whether an electric utility's customers or the QF has the right to the value of renewable energy credits, also known as green tags, associated with energy purchased by a utility from a QF.

PEC noted that the QFs and the Public Staff asserted that the value of any green tags should belong to the QFs because compensation for such green tags for environmental externalities have not been explicitly included in the calculation of the utilities' avoided cost. The utilities, on the other hand, assert that because a QF is entitled to avoided cost rates solely by virtue of its use of renewable fuels, the sale of power to the utility by the QF inherently conveys to the utility any green tags that result from the use of renewable fuels. As explained by the utilities, it is only because of the existence of certain attributes, in this case the renewable fuel source, that generators can be deemed to be QFs and therefore be eligible for preferential treatment.

PEC further noted that the NCSEA asserted that NC GreenPower provides a regional market for green tags. PEC in its Reply Comments asserted that this is incorrect. PEC explained that the question of green tag ownership between the QFs and the utilities has no impact on NC GreenPower, because the utilities agree that the green tags associated with the energy provided under the NC GreenPower program will be transferred to NC GreenPower. PEC then argued that NC GreenPower has therefore not created any need for the Commission to address the ownership of green tags.

PEC stated that by order issued on October 1, 2003, in FERC Docket No. EL03-133-000, the FERC declared that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey green tags to the purchasing utility absent express provisions in the contract to the contrary. The FERC explained that, while a state may decide that a sale of power at wholesale automatically transfers ownership of state-created green tags, that requirement must find its authority in state law, not PURPA. Thus, argued PEC, this matter is left to the discretion of the Commission.

PEC's central concern with ownership of green tags lies not with existing contracts in today's environment. Rather, PEC's fundamental concern is with the potential future implications if the Commission were to make a blanket ruling that the QFs retain ownership of green tags associated with energy sold to utilities. There is currently much debate in Congress regarding the current proposed national energy bill. One of the potential amendments being discussed is a renewable portfolio standard (RPS). An RPS bill was recently filed in the current session of the North Carolina General Assembly. An RPS would mandate that utilities obtain certain percentages of their energy requirements from specific generation types, usually renewable resources. According to PEC, one of the results of adopting an RPS is to create a demand for green tags, which can be used to meet the RPS requirement. If an RPS is imposed on utilities in North Carolina, either through state or federal action, the utilities would be required to obtain the energy from the designated renewable sources to meet the mandate. Presumably, the costs associated with these governmentally-mandated power purchases would be passed on to consumers as a legitimate cost of business. PEC asserted that therein lies the conflict. In order for a green tag to be recognized as legitimate, it can only be claimed once. If a utility purchasing renewable energy from a QF claims that the purchase satisfies part of its RPS requirement, then the selling QF cannot sell to another party a green tag derived from the same kWh sold to the utility. Conversely, if the renewable generator has sold the green tag to another party, the utility will not be able to use the purchase from the QF to satisfy the RPS, even though it is actually buying the kWh from the renewable generator. Under that scenario, the utility would incur additional costs to acquire the renewable energy from some other source, or go onto the open market and buy green tags from some other source. PEC pointed out that, in either case, the utility incurs additional costs that must be passed on to its customers.

Finally, PEC explained that there is no pressing need for the Commission to decide this matter at this time. Neither the Congress nor the General Assembly has passed legislation requiring a renewable portfolio which would involve renewable energy credits. Therefore, PEC concluded that this matter is simply not ripe for decision by the Commission.

Duke's Position

Duke also argued that the Commission should defer ruling on the ownership of renewable energy credits due to concerns regarding the future implications of such a ruling should the utilities become subject to an RPS either through state or federal action.

Duke stated noted that the issue of green tags was first raised in the biennial avoided cost proceedings in 2000. In Docket No. E-100, Sub 87, the Commission determined that a proposal for standard contract language to require that all environmental and resulting financial rights remain with the QF was denied without prejudice to further discussion of the issue in future proceedings.

Duke noted that NCSEA and CCWE have asked the Commission to address the issue of ownership of green tags in this proceeding. Duke suggested that it is not clear what value green tags from North Carolina QFs may have at this time. CCWE argued that it has had the opportunity to sell its green tags to out-of-state entities that are subject to some type of requirement to use renewable resources. Duke has no complaint about these green tags being used elsewhere unless and until North Carolina develops a renewable portfolio standard.

Duke observed that the Public Staff argued that since a coal-fired cogenerating QF is paid the same avoided cost rates that a QF using renewable fuels is paid, it is difficult to understand how the value of financial rights created by environmental externalities could be considered to be inherently included in avoided cost rates. Unlike all coal-fired generation, cogeneration is encouraged under PURPA because these facilities use fossil fuels for dual purposes — energy production and an industrial application. Thus, according to Duke, coal-fired QFs qualify for QF status precisely because they are deemed to be more efficient users of such fuels. Duke noted that the Public Staff has long argued that certain renewable energy QFs deserve higher rates due to their environmental attributes. For example, in addressing whether it is appropriate for Duke to use $0 value for capacity in the years that its Annual Plan did not reflect a need for capacity, the Public Staff stated that "because of the importance of small, distributed generation and the GreenPower Program, the Commission needs to be careful not to take action to their detriment." With respect to the 2.0 PAF for run-of-the-river hydro QFs, the Public Staff supported this higher rate because "these facilities are environmentally friendly and that G.S. 62-156 reflects a State policy encouraging their use." Duke argued that, in reality, North Carolina utilities already pay a premium for certain renewable QF capacity.

According to Duke, the requirement to offer long-term levelized rates further provides a benefit to eligible renewable QFs at the expense of the utilities and their customers. CCWE argued that developer-owners have assumed the risk of making an investment in renewable energy generation and have the rights to environmental attributes associated with such generation resources. The Public Staff supports requiring the utilities to offer long-term contracts in order to ensure that eligible QFs have a long-term market for their power so that they can obtain financing for development and maintenance. Duke argued that, to the extent utilities are required to enter into long-term contracts with QFs containing levelized rates, the investment risk is effectively shifted to the utility.

Duke further responded that it currently includes emissions allowance costs for NOx and SOx in the calculation of its avoided energy credits. Therefore, Duke's rates are already compensating QFs for the value of avoiding the cost of emission allowances, which reflects the current economic value of the environmental benefits of renewable resources under North Carolina and federal law. Duke explained that, when and if renewable energy credits become an additional cost to the utilities, the Commission will be faced with determining whether the cost associated with such credits should be included in the calculation of avoided costs in the future. Duke argued that if such costs are included in the calculation of avoided costs, then the utilities will be entitled to the green tags when they purchase energy and capacity from a QF. On the other hand, if the Commission rules that renewable energy credits are severable from the purchase of energy and capacity under avoided cost rates and are retained by the QF, then such costs, as well as the cost of emission allowances, should not be included in the calculation of avoided cost rates.

Additionally, Duke pointed out that NC GreenPower is a non-profit organization that is funded by the utility customers in North Carolina. This funding is used to encourage the development of renewable generation resources in North Carolina. Sales of the environmental attributes of QF projects that might be supported by NC GreenPower outside of the State potentially jeopardize the value North Carolina supporters of NC GreenPower receive from the program and such action could damage the public's support for NC GreenPower.

<u>Dominion's Position</u>

Dominion also believes that there is not enough information at this time to evaluate the issues surrounding ownership of green tags. Dominion stated that, in Docket No. E-100 Sub 101, concerning the Model Small Generation Interconnection Standard, the NCSEA asked that the Commission address the issue of the ownership of renewable energy certificates. The utilities countered that the NCSEA was reaching beyond the scope of those proceedings in requesting such relief. In its Order Approving, in Part, Proposed Interconnection Standard, the

Commission agreed with the NCSEA that the green tag ownership issue needs to be resolved, but that it would be better resolved in another docket. Specifically, the Commission noted that the ownership of green tags had been raised in these avoided cost proceedings and stated its intention to address the issue here.

Dominion noted that the green tag ownership issue was the only issue addressed by the two witnesses who appeared at the public hearing in these proceedings. However, as both the Public Staff and Duke have pointed out, the issue is more complicated than can be addressed in these avoided cost proceedings. As things presently stand, Dominion is of the opinion that the record regarding green tag ownership issues is not complete and that, in order for this Commission to make an adequate and reasoned decision, the record must be developed further.

CCWE's Position

CCWE explained that many states have developed statutory or regulatory programs which encourage or obligate load-serving organizations to either generate or purchase a specified percentage of its total load from renewable generation resources. In many instances, a utility or other load-serving entity can purchase on a secondary market certificates associated with energy from generation facilities that use renewable fuels and use those certificates in satisfaction of such "portfolio requirements." No such requirements or standards have been adopted in North Carolina as of this time. However, because green tags associated with the output of renewable generation resources located in North Carolina have value today to utilities subject to such standards in other states, the attributes of renewable generation in this state possess value in connection with the trading programs of other states. QFs located in this state that use renewable fuels to produce energy are qualified to issue green tags under the programs of some other states, and are interested in selling this attribute of their generation resources into the market for green tags in other states.

CCWE noted that most of the QFs that have raised this issue are interconnected with the transmission system of PEC, and PEC was the utility that addressed this issue most extensively, so the discussion here focuses on the arguments advanced by PEC, but the reasoning applies to all of the utilities in this State.

CCWE concluded that the resolution of this issue under existing law is not premature, and that the public interest would be served by removing any uncertainty arising under present law regarding the ownership of any value associated with the attributes of renewable generation resources located in North Carolina. In this regard, CCWE noted that disputes over the ownership of, and thus the right to use or sell, the attributes associated with the generation of renewable energy located in North Carolina clearly exist today. The existence of disputed claims of ownership creates uncertainty in the marketplace, which in turn is likely to result in the forfeiture of the potential economic value arising under the laws of other states, which benefits no one. CCWE identified three separate potential sales of RECs associated with its output that could not be consummated due to the competing claims of ownership asserted by PEC. Although PEC attempted to work with CCWE to develop documents that would permit CCWE to engage in the proposed sales, CCWE stated that none of the potential buyers were interested in purchasing the attributes subject to the claims of PEC. As a result of the uncertainties arising from the disputes over the ownership of these attributes, revenues that otherwise may have been collected under programs arising under the laws of other states were not collected by PEC or

CCWE. Foregoing such opportunities to maximize revenues available under the laws of other states does not benefit the public interest or ratepayers.

CCWE reasoned that addressing the issue in this proceeding is unlikely to have significant long-term effects on the utilities or ratepayers of this state. The determination of this issue under current law would not foreclose a different outcome in the event of changes in the laws or regulations of this state. The present economic value of green tags arises under the laws of other states, rather than under the laws of North Carolina; the fact that such values arise due to the laws of other states, however, would not preclude a change of the statutory or regulatory policies of this state. Moreover, utilities and QFs in this state are free under existing law to reach agreements that expressly address the sale or use of green tags under the programs of other states. This fact is particularly relevant here because many of the long-term contracts initially signed with QFs by the utilities in this state have expired already or will expire soon, and likely will be replaced with contracts of shorter duration. The parties to a new or amended contract can address expressly in the new contract the ownership of or entitlement to the attributes of renewable generation, and thereby avoid any confusion as to ownership or entitlement, without regard to whether the law or regulations in this state change in the future.

CCWE argued that the issue of the ownership of green tags under federal law has already been determined by the FERC. The FERC has squarely held that its avoided cost regulations did not contemplate the existence of green tags and that the avoided cost rates for capacity and energy sold under the contracts entered into pursuant to PURPA do not convey the green tags, in the absence of an express contractual provision. In reaching that conclusion, the FERC thoroughly reviewed the regulations adopted to implement PURPA, emphasizing that avoided cost rates were not dependent on the type of QF or its fuel source were intended to compensate QFs only for the capacity and energy sold.

CCWE offered that, significantly, what factor is not mentioned in the FERC's regulations is the environmental attributes of the QF selling to the utility. This is because avoided costs were intended to put the utility into the same position when purchasing QF capacity and energy as if the utility generated the energy itself or purchased the energy from another source. In this regard, the avoided cost that a utility pays a QF does not depend on the type of QF, i.e., whether it is a fossil fuel cogeneration facility or a renewable energy small power production facility. The avoided cost rates, in short, are not intended to compensate the QF for more than capacity and energy.

CCWE noted that, in ruling that PURPA did not confer upon public utilities any rights or claims to green tags, the FERC emphasized that it was not addressing any issue arising under the various state laws creating the green tags, but instead was ruling only that the claims of the utilities lacked a basis in federal law and would have to be decided under state law, not under PURPA or PURPA contracts.

CCWE continued that, as noted above, green tags are relatively recent creations of the states. Seven states have adopted RPS that use unbundled green tags. According to CCWE, what is relevant here is that the green tags are created by the states. They exist outside the confines of PURPA. PURPA thus does not address the ownership of green tags. The question, according to CCWE, becomes, therefore, whether PEC and the other utilities operating under the jurisdiction of this Commission have any claim under the law of this state to the green tags attributable to renewable-energy generation such as that operated by CCWE. CCWE stated that, as of today, no provision of North Carolina law grants any public utility any right or claim in or to any benefits associated with the environmental attributes of electric generation facilities which the utility does not own, or has not purchased. Moreover, the utilities regulated by this Commission cannot point to any statutes of another state which support the assertion that green tags do not belong to the owner of the generation, but instead belong to the utility that entered into a contract with a QF as required by PURPA. In its reply comments, however, PEC cited the filings made at the FERC by the Public Utilities Commissions of Maine and New Hampshire in the American Ref-Fuel Company proceeding. These filings generally supported the arguments made by some utilities that the long-term purchase of energy under PURPA contracts included the environmental attributes of the generation that produced such output, because most QFs that qualify for green tags achieved the status of a QF based on the use of renewable fuels. However, CCWE argued that the positions of these state agencies appeared to be based on regulatory determinations previously made in those states based the laws of those states. As previously noted, unlike Maine or New Hampshire, North Carolina has not yet adopted a renewable portfolio requirement or other programs dealing with generation attributes, either by statute or regulation.

CCWE also noted that other states which have addressed this issue have concluded that owners of QFs that use renewable generation resources to sell energy to a utility under avoided cost contracts retain the ownership and entitlement to use or sell green tags, unless the PURPA contract expressly dealt with the environmental attributes of the QF, or the purchasing utility pays additional compensation for the green tag. For example, CCWE noted that the Public Utility Commission of Texas concluded that additional compensation would be due a QF for the renewable energy credits associated with energy bought by a utility that purchased the output of the renewable generation resource under a PURPA contract. A similar conclusion was reached in a different procedural context by the Idaho Public Utilities Commission, which having previously declined to issue a declaratory ruling sought by a utility to confirm the treatment in subsequent rate cases of either releasing a claim to a QF's green tags, or voluntarily paying additional compensation for renewable energy certificates, subsequently held that the utility could voluntarily agree to purchase green tags from a QF, but noted that the price paid to purchase the environmental attributes of renewables would not be a PURPA cost and that the recovery of those additional payments in rates would be reviewed as would all other expenses and non-PURPA costs.

NCSEA's Position

NCSEA stated that existing renewable and combined heat and power generators do not currently receive any payment for the emission reductions they create. The current avoided cost process does not include monetary values for the reduced emissions from clean, renewable energy generation that utilities capture in NOx and SOx regulation. Further, the health care, agriculture, and tourism benefits that would result from cleaner generation are not calculated. These emission reductions now have value separate from the energy sold. Currently this value, in the form of recently established renewable energy certificates, must belong to the generator or be purchased separately by the utility. Most renewable energy projects built to supply NC GreenPower will be larger than NC GreenPower can initially support. These projects will need to sell their excess renewable energy certificates to other buyers to be feasible. NCSEA emphasized that it is very important that the Commission resolve the renewable energy certificate ownership issue in this avoided cost docket.

Public Staff's Position

With respect to existing contracts, the Public Staff submitted that the financial rights associated with renewable energy, such as green tags, should belong to the QF. The Public Staff noted that the issue of whether all environmental, and any resulting financial, rights remain with the QF or inure to the benefit of the utility by virtue of its purchase of the QF's power was raised by the public witnesses at the hearing in this docket. This issue has not previously been ruled upon by the Commission. The Public Staff's Initial Comments noted that, because of the adoption of programs providing renewable energy credits, tradable certificates/green tags, and other recognitions of the value of the relatively benign environmental attributes of renewable energy facilities, disputes have arisen as to whether an avoided cost contract inherently conveys to the purchasing utility any such financial recognitions and rights. By Order issued October 1, 2003, in Docket No. EL03-133-000, the FERC declared that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey such financial rights to the purchasing utility absent express provisions in a contract to the contrary. The FERC further declared that, while a state may decide that a sale of power at wholesale automatically transfers ownership of these financial rights, that requirement must find its authority in state law, not PURPA.

Based upon the discussions at the public hearing and other information known to the Public Staff, the Public Staff stated that it believes the time is right for a resolution of this issue. The utilities apparently believe that, because a QF is entitled to avoided cost rates by virtue of its use of renewable fuels, the sale of power to the utility by the QF inherently conveys any financial rights that result from the use of renewable fuels to the utility.

With respect to existing contracts, the Public Staff stated that the financial rights with respect to such environmental externalities should belong to the QF. A coal-fired cogenerating QF is paid the same avoided cost rates that a QF using renewable fuels is paid, so it is difficult to understand how the value of financial rights created by environmental externalities could be considered to be inherently included in avoided cost rates. Given that the Commission rejected an argument that such externalities should be included in the calculation of avoided costs in its Order in Docket No. E-100, Sub 74, the Public Staff believes it is clear that such compensation has not been included in avoided cost rates. Accordingly, the Public Staff further stated, that, on a going-forward basis, the issue is more complicated and deserves further consideration. The Public Staff, therefore, recommended that the Commission request further comment upon this subject.

Commission Conclusion

The Commission concludes that the time is ripe for a decision on this issue. Uncertainty as to the ownership of green tags under existing avoided cost contracts is effectively stifling the market for the sale of such credits by renewable generators in the State. PEC argues that the sale of power to the utility by a QF inherently conveys any green tags because a QF is entitled to avoided cost rates solely by virtue of its use of renewable fuel. Duke adds that the requirement to offer long-term levelized rates further provides a benefit to renewable QFs at the expense of utilities and their customers. The Commission disagrees with the utilities' argument that the availability to renewable generators of avoided cost rates or long-term levelized rates inherently conveys the green tags to the utility.

Section 210 of PURPA imposes a mandatory purchase obligation upon utilities requiring them to purchase the output from QFs at rates that are (1) just and reasonable to electric consumers and in the public interest, (2) not discriminatory against QFs, and (3) not in excess of the incremental cost to the electric utility of alternative electric energy. This "incremental cost of alternative electric energy," or avoided cost, is defined in Section 210(d) of PURPA as "the cost to the electric utility of the electric energy which, but for the purchase from [the QF] such utility would generate or purchase from another source." The FERC promulgated rules implementing Section 210 of PURPA and identifying what factors are to be considered in determining avoided costs. 18 CFR 292.304. As the FERC stated in its October 1, 2003 Order in Docket No. EL03-133-000,

> Significantly, what factor is not mentioned in the Commission's [FERC's] regulations is the environmental attributes of the QF selling to the utility. This is because avoided costs were intended to put the utility into the same position when purchasing QF capacity and energy as if the utility generated the energy itself or purchased the energy from another source. In this regard, the avoided cost that a utility pays a QF does not depend on the type of QF, i.e., whether it is a fossil-fuel-cogeneration facility or a renewable-energy small power production facility. The avoided cost rates, in short, are not intended to compensate the QF for more than capacity and energy.

The Commission disagrees with Duke that the inclusion of any of the utility's environmental costs compensates renewable generators for their green tags because not all QFs eligible for avoided cost rates generate green tags. Avoided cost rates are based upon the utilities' avoided costs, not the QFs' costs of generation or the value of any environmental benefits which may or may not be associated with that generation. Thus, the Commission agrees with and follows the FERC's decision that the question of ownership of green tags is not determined by whether the QF is selling its power to a utility under an avoided cost contract.

PEC and Duke further argue that their fundamental concern with the issue of the ownership of green tags lies with the potential future implications if a state or federal RPS were to be adopted mandating that utilities obtain certain percentages of their energy requirements from renewable resources. PEC argues that a determination that green tags are retained by the renewable generator would cause the utility to incur additional costs in the event an RPS is imposed. The Commission recognizes that one potential consequence of its decision that the sale of power by renewable generators at avoided cost rates does not convey the right to green tags is that the utility might incur an additional cost to comply with a future RPS. However, this question must be determined in the context of any future legislation, not in determining the ownership of green tags under current state and federal law.

Lastly, Duke argues that the rates of certain run-of-the-river hydro facilities include a 2.0 PAF because they are "environmentally friendly" and, therefore, are being compensated for their green tags with this premium. The Commission disagrees. First, a PAF is applied to all QF rates to allow the generator an opportunity to recover the full capacity credit. Secondly, while the 2.0 PAF may have been justified in the past, in part, upon G.S. 62-156 and the state policy encouraging small hydro generating facilities, not all hydro facilities included in G.S. 62-156 are eligible for the higher PAF. Thus, while QFs eligible for the 2.0 PAF may be generating green tags, the PAF is not designed to compensate them for such.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 10

Calpine's Position

Calpine provided extensive comments on this topic. It argued that an appropriate, accurate, and administratively straightforward methodology for calculating the price of "as available" energy is for QFs to receive an estimate of hourly avoided costs on the day preceding the QFs' actual deliveries determined in accordance with a known model and inputs administered by the purchasing utility.

Calpine noted that a number of parties commented about the pricing of "as available" energy sold by a QF to a utility. 18 C.F.R. 292.304(d) states that each QF has the right to provide: (1) "energy as the QF determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery" or (2) "energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the QF exercised prior to the beginning of the specified term, be based on either: (i) the avoided costs calculated at the time of delivery; or (ii) the avoided costs calculated at the time the obligation is incurred." Accordingly, regardless of whether the energy is made available as determined by the QF or is made available pursuant to a contract, the QF has the right to receive a price based on the avoided costs of the utility calculated at the time of delivery.

Calpine stated that the Reply Comments of PEC appear to argue that QFs larger that 5 MW have only one option -- to negotiate purchased power rates -- and that PEC would completely eliminate the "as available" variable energy rates from its proposed rate schedule, despite the Commission's directive in Docket No. E-100, Sub 96 that such rates be included. The Public Staff, Duke, and Calpine all advocated in their comments that PURPA requires a methodology by which "as available" energy can be sold to a utility at a price based on the avoided costs of the utility calculated at the time of delivery.

Calpine noted that, in the last biennial avoided cost proceeding, Duke argued that the appropriate rate at which utilities should be required to purchase "as available" energy from QFs is the prevailing hourly market price, which represents the utilities' avoided energy cost on a real-time basis, and it continues to assert this position in the current proceeding. As recited in the Order in Docket No. E-100, Sub 96, Duke explained that, depending on when the QF actually delivered its "as available" energy, the cost of energy avoided by the purchase would be higher or lower than the two-year average prices that had been established in previous biennial dockets.

Calpine noted in its Initial Comments that numerous other state commissions have recognized PURPA's "as available" energy pricing requirement and developed methods for determining avoided costs at the time of delivery. These states have determined that such "time of delivery" methodologies are not only workable and practical, but beneficial and fair both to ratepayers and to QFs. Evaluating the relative merits — appropriateness, accuracy, and simplicity — of these different methodologies, Calpine proposed general principles to guide the pricing of "as available" energy. As noted above, such pricing would be structured in a way that would approximate the avoided costs in the hour that the energy is delivered and would be feasible and practical for utilities to implement. Calpine proposed that rate schedules for purchasing "as available" QF energy, include:

> A utility shall provide any requesting QF day-ahead avoided energy cost estimates for each hour using the best available modeling methods for unit commitment pricing. Modeling shall include system sales and actual purchases known at the time. The calculated avoided cost shall represent the displacement of the most expensive resources that would have otherwise been expected to serve the displaced load each hour.
>
> A utility will take delivery of all QF energy offered at any point on its system that has sufficient capacity to receive it.
>
> A utility shall preserve all data related to its calculation of the day-ahead avoided cost estimate. Upon request of a purchasing QF or the Public Staff, utility shall make this data available for public inspection, as required by Section 292.302(b) of the PURPA regulations. Any QF or the Public Staff may file a complaint with the Commission if it believes that Utility has not accurately and correctly used the methodology, or has used improper data inputs, or has otherwise failed to purchase QF energy at a rate that reflects its avoided costs calculated at the time of delivery.

Calpine explained that this procedure for compensating QFs for energy, whether "as available" or under a term contract, is consistent with PURPA requirements, is reasonable to implement, and would be fair both to QFs offering this energy and to the electric consumers of North Carolina, who will pay no more for energy than the costs the utility avoids by purchasing QF energy.

Calpine stated that the utility receiving QF energy also benefits from this arrangement. It saves run-hours on its equipment and, with proper price signals, would have the energy available in times of highest demand, thereby adding to its available generation resources, portfolio diversification, and reliability margin.

According to Calpine, any valid operating concern regarding "as available" sales of QF energy can and should be incorporated into the avoided cost methodology approved by the Commission. With respect to PEC's contention that a QF should be deprived of "as available" sales because of ineligibility for standard rates, Calpine suggests that PEC is once again confused in its understanding of the issues at hand. In the 2003 Order, the Commission summarizes the Public Staff's position on this issue as follows: "PEC's argument that granting larger QFs the right to the standard variable capacity rate will inevitably cause a utility to pay more than its avoided costs must be rejected because it confuses the policy issue of whether standard rates should be made available to a QF with the determination of avoided cost." Two years later, PEC continues to proffer the red herring of standard rates, which is a concept that has nothing to do with the question of how to determine avoided costs at the time of delivery of "as available" energy. PEC correctly points out that PURPA and its implementing regulations do not require standard rates for purchases from QFs larger than 100 kW. PURPA's implementing regulations do affirmatively require that a QF have the option to provide energy on an "as available" basis and receive avoided costs calculated at the time of delivery. Thus, it is obvious that standard rates do not equate to rates for "as available" energy. Calpine asserted that, because all applicable authority and precedent establish that a QF has the right to sell energy on an "as available" basis and receive avoided costs at the time of delivery, the only issue remaining is how to determine such avoided costs.

Calpine emphasized that another reason PEC's concern about the market impact of avoided cost information is unfounded comes from basic laws of economics. As a fundamental principle, market price is established based on what a buyer is willing to pay and what a seller is willing to accept. Supply and demand are the predominant drivers. Cost is not the predominant market driver. If PEC perceives that its buying market price is being driven upward toward its published cost due to sellers' offers, then it should turn down such troublesome offers and let the market decide what sellers are willing to accept. As a savvy market player, PEC will presumably always seek the lowest cost for its retail customers.

Calpine noted that a review of the market participants in the Virginia and Carolina's Regional Reliability Council (VACAR) reveals an additional reason to discount any fear of market impairment. QFs are only a small part of the VACAR market - a market of large players with large appetites for energy. The VACAR market has over 70,000 MW of installed capacity with less than 5000 MW of QF generation. Only a fraction of the QF generation is not already under contract, and most of those contracts are with investor-owned utilities. A further diminution of QF impact in the VACAR market results from the fact that transmission into VACAR, and especially PEC (either its east or west control area), is extremely limited. Out-of-state QFs have only a limited opportunity to supply QF energy to VACAR utilities. To illustrate, of the 1500 MW of QF energy Calpine has available in Alabama, Calpine proposed selling only 150 MW to PEC due to transmission constraints. In fact, the sum of all 9 CP&L transmission interfaces is limited to only 330 MW for the summer months of 2005.

Calpine stated that its willingness to execute confidentiality agreements and confirm any prohibition on sharing day-ahead price information should mitigate any concern about the harmful impacts of the disclosure of such information. Even without the industry-wide scrutiny on corporate compliance, ethical behavior, and controls mandated by Sarbanes-Oxley, utilities have assurances that confidential information will be treated with the highest degree of integrity due to the self-policing nature of bad faith actions in an industry built on trusting relationships.

Calpine further explained that, having established that estimates of avoided costs are contemplated by PURPA, the next issue to explore is the use of the variable energy rate as a proxy for avoided costs calculated at the time of delivery. All parties, including PEC, acknowledge that fixed rates increase the risk to the utility and its customers due to the inevitable mis-match between the fixed rates and actual costs.

Calpine submitted a proposal which it claims is simple to administer and automatically takes into account operational complexities and appropriately values "as available" energy close to the time of delivery in an accurate manner consistent with current utility procedures and methodologies.

<u>PEC's Position</u>

PEC responded that PURPA does not require a utility to offer a QF a day-ahead hourly avoided cost rate and that requiring a utility to do so would harm both the utility and its customers and be administratively burdensome. PEC stated that the reason Calpine wants such an avoided cost rate is that Calpine wants to be able to choose, each day, on an hourly basis, between selling the energy from its Alabama facility into the competitive wholesale market or to PEC, whichever is offering the highest price. In other words, according to PEC, Calpine wishes to use PEC as a safety net, selling to PEC only when PEC's forecasted hourly avoided cost rates exceed the market rates Calpine expects to enjoy the next day.

PEC noted that the Commission determined in the previous avoided cost proceeding that the requirements of 18 C.F.R. 292.304(d) are satisfied by the variable energy rate. The Commission found that a utility's on-peak and off-peak variable energy rates represent a utility's best estimate of its average avoided energy costs for all on-peak and off-peak hours. The Commission also explained that attempting to administer an actual day-ahead hourly avoided cost rate would be administratively difficult given the fact that new rates would be calculated for each hour for each day of the year.

PEC pointed out that, in its Initial and Reply Comments, Calpine cited decisions by various other state commissions in this regard. However, federal law specifically delegates to each state the authority to implement the FERC's rules. 16 U.S.C. 824a-3(f). Thus, this Commission is free to establish its own rules with regard to an "as available" rate provided such rates are consistent with the applicable federal laws and FERC regulations.

As explained by PEC, a literal application of the FERC rule which states that a QF is entitled to rates based upon the purchasing utility's avoided cost calculated at the time of delivery does not support Calpine's assertion that it is entitled to a day-ahead forecasted rate. Rather, a literal application of the words in question would require a utility to pay a QF the actual cost that is avoided, which can only be calculated after the sale. PEC stated that this is exactly what the Florida rule requires, which is cited by Calpine in support of its arguments. Florida Public Service Commission Rule 25-17.0825(2)(a) provides that a utility's "as available" rates are defined as the utility's <u>actual</u> avoided energy cost.

PEC also argued that it would be harmful to it and its retail customers to require it to provide QFs with a day-ahead hourly forecasted rate. PEC asserted that if it is required to provide such a rate to Calpine, and potentially every other QF in the Southeast, PEC would not be in a position to purchase power for the benefit of its retail customers at the lowest possible price, because many of the generators in the region would then know the price that they must bid in order to make an offer that is more attractive than PEC's forecasted avoided cost. As a result, in all probability, such generators will not bid as low as they otherwise would have because they will know for certain the price that must be met to make a competitive bid. PEC noted that, in this case, Calpine is attempting to operate its QF as both a QF and a merchant facility, depending upon which market (the competitive wholesale market or PEC's avoided cost rates) offer the better price. PEC asserted that the purpose of PURPA was to create a market for the sale of QF power, not to create a safety net for the sale of merchant generation, which is how Calpine now wishes to use the Commission's avoided cost proceeding.

According to PEC, none of the parties to this proceeding have provided any persuasive evidence to support any change in the Commission's position on this issue. The Commission's application of PURPA has provided financial predictability to QFs, appropriate and accurate rates, and a mechanism that does not create a substantial administrative burden on the Commission or the state's electric utilities.

Regarding the Public Staff's question as to whether the provision of, and publication of, a utility's avoided costs that are closer to being "real time" would have any effect on a utility's ability to purchase power at prices lower than its avoided costs, PEC explained in its Comments that the cost of purchased power would be affected by market knowledge of a utility's costs. This would be especially pronounced when such knowledge was available in close proximity to the delivery period. Advance knowledge of a utility's avoided costs would essentially provide both a floor and a ceiling price from which prices would be negotiated in that market. This would limit the utility's ability to negotiate at rates that are less than its avoided cost and thus, ultimately, result in higher costs for utility ratepayers.

PEC noted that, under principles of economic dispatch, the costs avoided by utilities would vary widely based on the amount of energy supplied. The avoided cost of displacing a peaking facility would be significantly different from those associated with the costs avoided by displacing an intermediate facility. For these reasons, the rate would not only differ by hour but would vary by the amount of energy, or blocks of energy, delivered. PEC argued that, if the Commission were to approve and mandate such a measure, there would be additional costs associated with that measure and a significant administrative burden. PEC concluded that, given these circumstances, the use of prevailing market prices would be a preferable basis for the "as available" rate when compared to such a pricing scheme based on avoided costs.

Public Staff's Position

The Public Staff responded that, given that PURPA requires that a QF be given the option of providing energy on an "as available" basis at the purchasing utility's avoided cost estimated at the time of delivery, a methodology should be approved for calculating avoided energy costs that are closer to being "real time" costs than the variable energy rate. It explained that the availability of the "as available" energy methodology and information pursuant thereto should be subject to the QF seeking such an option agreeing that all such information provided to it would be treated as confidential and proprietary information.

According to the Public Staff, Duke in its Reply Comments stated that it had advocated for "as available" rates based upon the prevailing hourly market price in 2002 and that it continued to support this position. However, Duke further argued that Calpine does not own any QFs directly interconnected with a North Carolina utility and therefore that the standard rates and contract terms and conditions are not available to Calpine.

The Public Staff stated that, in PEC's Reply Comments, PEC noted that it had been in negotiations with Calpine for several months and that Calpine intended to use PEC as a safety net. PEC asserted that providing Calpine with PEC's day ahead hourly forecasted avoided costs would harm PEC's retail customers. The Public Staff's Reply Comments noted that this issue was raised and briefly discussed in the last avoided cost proceeding. In its proposed order, the Public Staff recommended that the Commission solicit comments from interested parties with respect to this issue. The Commission ruled, based upon the information before it, in the last avoided cost proceeding that a utility's approved variable energy credit constituted the utility's "as available" rate, and concluded that, if other rates were used, the Commission would not be able to insure their accuracy and appropriateness.

The Public Staff asserted that PURPA explicitly provides that a QF has the option to provide energy on an "as available" basis at the utility's avoided cost at the time of delivery. The regulations, however, do not define "at the time of delivery." The narrowest interpretation of this phrase would require a utility's avoided costs to be determined just after energy was delivered because any other process would involve an estimate of avoided cost rather than actual avoided cost. It is clear, however, that PURPA allows estimates to be used. The question, according to the Public Staff, thus becomes whether the two-year variable rate should be used as this estimate or whether another methodology would be appropriate and/or more clearly consistent with PURPA. The Public Staff stated that it believes that it would be appropriate for the Commission to develop and approve a methodology for determining avoided costs closer to the time of delivery than the two-year variable rate. This does not necessarily mean that day-ahead estimates are required. As demonstrated in Calpine's Comments, at least one state, Connecticut, has used a monthly forecast.

The Public Staff has met with Calpine on several occasions and discussed the matter extensively with PEC. PEC is not opposed to providing a methodology by which Calpine could determine whether or not PEC's relatively "real-time" avoided costs were high enough for Calpine to be willing to sell to PEC. However, PEC objects to the routine publishing of such information because of the potential competitive harm that could result to PEC's ratepayers. The Public Staff noted that it had attempted to get information from the states cited by Calpine with respect to PEC's confidentiality concerns, but that it had not been able to obtain enough information to take a position with respect to the validity of the concerns or the best method for obviating such concerns.

The Public Staff concluded that the impasse between PEC and Calpine might be better resolved by "mediation" rather than within the context of the generic avoided cost proceeding or, alternatively, that the Commission might prefer to take all of the comments on this issue and frame issues for further consideration. Clearly, there is some merit to a process by which PEC could displace its higher-priced on-peak CT generation by purchasing available energy from Calpine. If such a process could be implemented without the asserted downside risks, it would be good public policy to pursue such a option.

In its proposed order, the Public Staff noted that other states require that relatively "real time" energy rates be made available to QFs, either apparently without concern about confidentiality or by adopting mechanisms to protect market sensitive information. The Public Staff referenced an order of the Georgia Public Service Commission, which approved a formula by which "real time" prices would be given to QFs by no later than 4:00 p.m. on the afternoon preceding QF deliveries. The approved formula is as follows: the QF avoided energy price equals the utility's system lambda, times a marginal cost multiplier, times the difference between spot fuel costs and the average of total fuel portfolio costs (with some exclusions), plus avoided O&M costs, plus avoided environmental costs, plus avoided start-up costs. The availability of the "as available" energy methodology and information pursuant thereto is subject to the QF agreeing that all such information provided to it is confidential and proprietary information and that it will not disclose such information at the time it receives it and for a period of two years thereafter to any person except those of its officers, employees, and agents who need to know the confidential information in order for the QF to sell pursuant to the "as available" methodology and who agree to maintain the confidentiality of such information for two years from the receipt of such information.

The Public Staff also noted that Florida requires that each utility publish a tariff for the purchase of "as available" energy from QFs, with the rate of payment being as defined in the rule. The Florida rule provides that avoided costs for this purpose shall be all costs the utility avoided due to the purchase of "as available" energy, including the utility's incremental fuel, identifiable variable O&M expense, and identifiable variable utility power purchases. Demonstrable administrative costs required to calculate avoided energy costs may be deducted from avoided energy payments. The rule further provides that each utility shall calculate its avoided energy costs on an hour-by-hour basis, after accounting for interchange sales that have taken place, using the utility's actual avoided energy cost for the hour, as affected by the output of the QFs selling to the utility. The Public Staff also noted that the availability of these rates is not limited to directly connected QFs.

The Public Staff opined that the use of the variable energy rate as the "as available" rate does not comply with PURPA. According to the Public Staff, leaving this matter solely to negotiations would not satisfy the requirement that QFs be provided with the option of selling energy on an "as available" basis.

Commission Conclusion

In the last proceeding, the Commission concluded that the variable energy rate is intended to be the "as available" rate and required the utilities to reword their tariffs, as necessary, to make it clear that QFs always have the option of selling energy to the utility at that rate. The issue to be decided in this proceeding is whether the two-year variable rate should continue to be used as this estimate or whether another methodology would be appropriate and/or more clearly consistent with PURPA.

The exact method of determining the "as available" rate is not specified in the FERC regulations implementing Section 210 of PURPA. In discussing this purchase requirement, the FERC stated that PURPA did not intend a "minute-by-minute" determination of avoided cost. The FERC further stated that "the rates for purchases [on an as-available basis] are to be based on the purchasing utility's avoided costs estimated at the time of delivery," but did not specify when that estimate should be made. In fact, Section 292.302(b) of the FERC regulations suggests that such estimate should be established in the biennial proceeding, requiring only that utilities every two years "make available data from which avoided costs may be derived," including "estimated avoided cost ... stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the next calendar year and each of the next 5 years." The tariffs approved by this Commission incorporate this daily and seasonal peak and off-peak differentiation. Therefore, there is no indication that the Commission's current practice violates any provision of PURPA or the FERC rules.

The Commission concludes that its current practice is not only legal, but also appropriate. The Commission has treated the variable energy rate as the "as available" rate for many years and few complaints have been raised. The Commission, at the urging of one QF, considered this issue in the last avoided cost proceeding and reaffirmed its prior practice. Further comments have been received in this proceeding, again largely at the instance of a single QF. The Commission has carefully considered the arguments herein, and the Commission again concludes that its current practice of treating the variable energy rate as the "as available" rate required by PURPA provides the advantages of predictability and certainty for the QFs and ease of administration for the utilities and that it should be continued.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 11

PEC's Position

PEC observed that, beginning with the Commission's decision in Docket No. E-100, Sub 53, the Commission found that the megawatt capacity limit for standard rate QFs should be based upon contract capacity because some generators may consume some of that capacity internally and these generators should not be foreclosed from the standard rates. In its Reply Comments in this docket, PEC agreed that the Commission should continue to use a QF's contract capacity for determining eligibility for standard rates; however, PEC requested that the Commission revise this decision to establish a requirement that any capacity in excess of the contract capacity must be consumed internally by the QF.

Commission Conclusion

The Commission agrees that the standard rates are meant to be available only to small capacity QFs as opposed to larger ones wishing to take advantage of standard rates for a portion of their overall generation. The Commission therefore concludes that any capacity in excess of the contract capacity of standard rate QF generators must be consumed internally by the QF.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 12

CCWE's Position

CCWE observed that PEC has proposed to use the peaker method to develop its avoided costs for purposes of determining the capacity credit portion of its total avoided costs. Under the peaker method, the cost of a combustion turbine (CT) is used to develop avoided capacity costs based on the theory that the incremental capacity costs avoided by PEC in any hour should not exceed the capacity costs for the lowest cost capacity available or likely to be available to PEC. CCWE noted that, consistent with this theory, PEC has used a computer model which calculates and compares system incremental costs with and without a hypothetical block of 100 MW of QF deliveries to develop its avoided costs for the proposed on-peak and off-peak credits for energy delivered by an interconnecting QF. According to CCWE, the effect of this methodological approach in this proceeding has been to reduce the projected avoided capacity rates from those established in the last biennial proceeding, even though the cost of a simple cycle CT has not diminished and may have increased in the interim since those rates were established. Moreover, the combination of these methods has resulted in a proposed capacity credit which is slightly more than half the levelized bus-bar costs used by PEC in the Screening of Generation section of its most recently filed Annual Resource Plan. CCWE argued that, because the estimated avoided capacity costs developed by PEC using the peaker method vary so dramatically from the actual costs for new simple cycle CT capacity and the capacity costs used by PEC to plan its system growth, PEC has failed to demonstrate that the proposed reduction of its capacity credits is reasonable or accurately reflects the capacity costs PEC is likely to avoid in the future from purchasing capacity from QFs. As a result, CCWE argued that PEC's capacity credits should remain unchanged from those last established by the Commission.

PEC's Position

The Public Staff expressed concern about the amount of the decrease proposed by PEC from its current avoided capacity rates. Subsequent to the filing of the Public Staff's Initial Comments and prior to the filing of PEC's Reply Comments, PEC and the Public Staff agreed to revised capacity credits which are higher than those initially proposed by PEC. These higher capacity credits are reflected in PEC's proposed Revised CSP Schedule 22A, which was attached to PEC's Reply Comments.

Public Staff's Position

The initial comments of CCWE and the Public Staff raised a number of concerns about the significant proposed reduction from PEC's current capacity rates. The Public Staff stated that PEC's proposed rates for hydroelectric QFs without storage capacity are between 16% to 18% lower than the currently approved capacity rates and that its proposed rates for all other QFs are 19% to 22% lower than currently approved rates.

The Public Staff further noted that the Commission has not specifically rejected the changes made by PEC in other proceedings (e.g., it has both ruled against using the generic data used by PEC when individual utility data is available and supported the use of such data in specific avoided cost proceedings). However, the Public Staff expressed concern whether such a large cumulative decrease in capacity costs is warranted. In their Reply Comments, both PEC and the Public Staff discussed a revision to the capacity rates. The Public Staff stated that it understood that PEC would be filing a revised rate schedule to resolve one of the concerns (i.e., PEC's proposed change in the method by which it calculated the revenue requirement related to the construction of a CT). The revised rate schedule would contain rates that reflect a real economic carrying charge rate of 10.835%, as compared to the 10.325% shown in PEC's November 1, 2004 filing. The revised carrying charge rate increases the variable, 5-year, 10-year, and 15-year capacity rates by approximately 4.7% from those that were initially proposed by PEC. The Public Staff indicated that it intends to continue to look at such issues and, therefore, these adjustments should not be considered to be precedential for future proceedings. PEC subsequently filed the revision in accordance with the Public Staff's stated understanding.

Commission Conclusion

The Commission concludes that PEC's proposed revision to its capacity credits, as discussed in the Public Staff's and PEC's Reply Comments, should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 13

NCSEA's Position

NCSEA observed that capacity payments are applied only during peak hours. Allowing utilities to move holiday off-peak hours to a peak day if the holiday falls on a weekend has no justification and needs to be changed.

PEC's Position

PEC noted that it has been asserted in this proceeding that utilities should no longer be allowed to treat holidays that fall on a weekend but are observed on a weekday as off-peak hours for purposes of establishing avoided cost rates. PEC explained in its Comments that the Commission specifically established the current practice with regard to this issue in Docket No. E-100, Sub 74. PEC in its Comments provided further support for the Commission's prior decision, explaining that the load characteristics of a holiday, occurring during a weekend but observed on an adjoining weekday, do not resemble the load profile of a "standard" weekday.

PEC also pointed out in its Comments that the classification of these days as off-peak periods has been employed and approved by the Commission for utilization in PEC's time-of-use-based retail tariffs.

Commission Conclusion

NCSEA has not identified any new evidence that would support a change in the Commission's policy with respect to the treatment of holidays that fall on the weekend but are observed on weekdays, and, therefore, the Commission reaffirms its decision on this matter.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Duke's Position

Duke argued that elimination of the Option A set of on-peak and off-peak hours in its Schedule PP rates for new contracts is reasonable and appropriate. In the last avoided cost proceeding, Duke introduced a new set of on-peak and off-peak hours for Schedule PP, designated as Option B. Option B on-peak and off-peak hours correspond to the times when customer demand and the cost of generation supply is usually highest. Option B hours utilize the same on-peak and off-peak hours as Duke's Optional Power Service, Time of Use retail schedule applicable for service to non-residential customers. Option B has fewer on-peak hours during the year compared to the traditional Option A Schedule PP on-peak hours. The traditional Option A set of on-peak hours spread capacity credits over 4,160 on-peak hours per year. Thus, a QF had to run 4,160 hours to receive full capacity credit. The Option B set of hours spreads capacity credits over 1,860 on-peak hours per year. Spreading energy and capacity costs over this smaller number of on-peak hours increases on-peak rates on a cents/kWh basis. The result is that QFs have to run fewer hours during the year to receive full capacity credits. Nothing in the Option B hours limits the number of hours that a QF may choose to operate. According to Duke, this option simply makes it easier for a QF to receive full avoided capacity costs, because it has to run fewer hours to receive full credit.

In an effort to simplify the administration of contracts and metering programming required to support two different sets of on-peak rates, Duke proposed to begin using this Option B set of on-peak and off-peak hours for all new contracts under Schedule PP. Duke believes this single set of on-peak hours will be more beneficial to all QFs. Duke argued that shorter on-peak hours will also help run-of-the-river hydro facilities to receive full capacity credits because they will have to run fewer hours of the year to receive capacity credits and that, because these hours are closely aligned with the hours of Duke's system peak demand, all QFs will be encouraged to supply electricity when it is most needed.

Public Staff's Position

In its Initial Statement, the Public Staff opposed the elimination of Option A, noting that Option B may prove to be attractive to some QFs, but it is doubtful that most QFs would choose to limit so significantly the number of hours over which they would need to operate in order to be paid full avoided costs. The use of a higher PAF for run-of-the-river hydro QFs is based upon their lack of control over the flow of water. Reducing the number of hours during which they get paid is very likely to exacerbate the situation, rather than improving it. The Public Staff stated that it had no objection to Option B being available as an additional option, but opposed it being the only available option.

Commission Conclusion

The Commission concludes that Duke's proposal to eliminate its current Option A, which spreads capacity credits over the traditional number of hours, should be rejected. As noted by the Public Staff, reducing the hours during which a QF must be operational to receive full capacity credit may not be attractive to some QFs. However, the Commission agrees that Duke should be permitted to offer Option B as an additional option available to QFs.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 15

CCWE's Position

According to CCWE, PEC should cause to be filed with the Commission standard contracts for the interconnection of QF facilities in excess of 5 MW, such that only genuinely site-specific conditions or issues will vary from one contract to the next. Moreover, such contracts should clearly state the facility and other costs that will be charged for interconnection with the utility's system at the distribution level and the lower amount of such costs that will be charged for interconnection with the utility's system at the transmission level. Finally, such contracts should also provide that, after PEC has recovered the costs for the interconnection facilities required to interconnect a QF to its system, including depreciation and/or replacement costs, the monthly facilities charge should expire and PEC would be limited to the recovery of its operation and maintenance charges only.

CCWE stated that PEC must exclude from the costs recoverable under its interconnection agreements with existing QFs in this state all costs, if any, that are or would be treated by the FERC as "network upgrades" and allowed as an element of cost recovery in the transmission rates allowed for that utility by the FERC. Standard terms and conditions for the interconnection of QFs reduce the risk of discriminatory terms and conditions and the potential use of interconnection agreements to discourage the development of cogeneration and small power production facilities. According to CCWE, making standard terms and conditions broadly available also will likely make negotiation of any site-specific amendment less contentious and burdensome, because such changes likely would be made only to the terms and conditions that genuinely are site-specific or project-specific.

CCWE noted that two specific issues pertaining to interconnection charges have been raised by the filings in this proceeding. First, it appears that some of the interconnection agreements entered into by QFs and utilities in this state charge QFs a uniform facilities charge, regardless of whether the point of interconnection for the QF is at the distribution or transmission level. To include costs associated with distribution facilities for a QF that interconnects at the transmission level is both unreasonable and unreasonably discriminatory. It is unreasonable because the utility is recovering a contribution to distribution costs from QFs that are not using the distribution facilities. It is unreasonably discriminatory because QFs which are interconnected at the distribution level pay no greater facilities charge than a QF interconnected at the transmission level, even though more utility facilities are used for distribution level interconnections.

The second issue cited by CCWE relates to the collection of excessive monthly facilities charges by utilities that insist on collecting a monthly facilities charge in an interconnection agreement with a QF, even though the utility will have collected under the previous years of the contract more than sufficient revenue to recover the reasonable costs of interconnecting that QF. The comments of CCWE, for example, reveal that its initial interconnection agreement with PEC included a 2% monthly facilities charge that PEC has collected (or will collect) for each month of the 15 years of the initial term of that agreement (from 1990 through December 2005). These collections have produced a nominal recovery nearly three times higher than the costs actually incurred by PEC for installing facilities over and above those normally absorbed by PEC. CCWE asserted that, in connection with the renegotiation of the interconnection agreement associated with potential energy and/or capacity sales in the future, PEC should be allowed to recover its operating and maintenance costs, but cannot reasonably continue to charge or collect a monthly facilities fee for the same interconnection expenses from 1990 that justified the collection of a monthly charge for facilities during each month over the last fifteen years.

CCWE argued that allowing a utility to "double recover" for the same costs is not in the public interest. Because the FERC has allowed or proposes to allow transmission owners such as PEC to recover, as network costs, the costs of interconnections and/or related upgrades of its system when those costs relate to items physically removed from the physical point of interconnection, the inclusion of any such costs in the standard interconnection agreements with QFs approved by the Commission would effectively allow PEC to recover those costs twice, once through its transmission charges and a second time under the QF interconnection agreement.

NCSEA's Position

According to NCSEA, there should be a higher differential between rates for projects interconnected at the distribution level and those interconnected at the transmission level. The high cost and difficulty of building and maintaining transmission should also be considered. Current proposed differences appear to only account for the efficiency gains of delivering the energy closer to the load.

Also, NCSEA argued that renewable generation projects are often made uneconomical by the addition of backstanding and metering charges. While an individual distributed generator going off line will cause the interconnected utility to provide generation, the existence of numerous distributed generation generators on the grid of different technologies and in different geographic locations essentially eliminates the overall effect on the system of any one or two generators going off line. Therefore, NCSEA concluded that these types of charges should be very small and calculated on a system-wide average basis.

NCSEA further commented that all distributed generation should get credit for reductions in system upgrades and that utility planning should include finding locations where the addition of distributed generation would reduce the need for upgrades. Small distributed generation system metering charges, advertising requirements and other similar charges need to be reconsidered and reduced to take into account the differences between large QFs and distributed generation.

PEC's Position

PEC stated in its Reply Comments that differentials already exist in PEC's capacity and energy rates that distinguish between projects interconnected at the distribution level and at the transmission level. These differentials are appropriately limited to the recognition of transmission marginal capacity and energy losses. While distribution facilities are sized based on meeting the foreseeable needs of local load centers, their design criteria would not be impacted by projects eligible for the standard CSP Schedule due to their small size and non-dispatchable operating characteristics.

PEC noted that, in this proceeding, as in the previous proceeding, an intervenor has asserted that PEC's monthly facilities charge is excessive and should either be reduced or eliminated. In Docket No. E-100, Sub 96, PEC explained that this charge is both appropriate and necessary to recover its costs. In the Commission's Order issued in Docket No. E-100, Sub 96, the Commission ruled that, because PEC's monthly facilities charges are applied to all of its retail customers, as well as QFs, the avoided cost proceeding was not the appropriate docket in which to investigate this matter. The appropriate forum for resolution of this issue would be a complaint filed by a QF.

In the previous avoided cost proceeding, PEC explained that its monthly facilities charge was established in its last general rate case as part of its base rates and that any attempt to change these rates would constitute single issue ratemaking and violate G.S. 62-133.6, which prohibits any change in PEC's base rates, except in certain extraordinary circumstances, prior to January 1, 2008. PEC further noted that, in Docket No. E-100, Sub 79, the Commission found that a QF wishing to challenge the 1% facilities charge when a customer makes a contribution in aid of construction should do so in a complaint case.

Commission Conclusion

The Commission finds, as it did in Docket No. E-100, Sub 96, that any QF wishing to challenge the monthly facilities charge or other interconnection practices and procedures as applied to that QF should do so in a complaint proceeding. These issues are not necessarily specific to QF facilities and a decision on these matters is inappropriate as a part of this proceeding.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-17

The Commission makes the following conclusions with respect to the proposed schedules and standard contract terms and conditions:

The rate schedules and standard contract terms and conditions proposed in this proceeding by PEC, Duke, and Dominion should be approved except as otherwise discussed herein. The utilities should be required to file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order, to be effective 10 days after their filing. The utilities' filings shall go into effect 10 days after they have been filed unless specific objections as to the accuracy of the calculations or conformity to the decisions herein are filed within that 10-day period. PEC, Duke, and Dominion should file supporting documentation showing the calculations made to arrive at their avoided cost rates, highlighting any additional changes required by this Order.

All utilities are urged to carefully review their tariffs and make such revisions as needed to ensure that the tariffs accurately reflect the provisions ordered herein, or any more generous terms that a utility may elect to offer.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 18

WCU does not generate its own electricity; it buys its power wholesale from Nantahala (a division of Duke Energy Corporation) at rates approved by the FERC. The avoided cost formula proposed by WCU would reimburse a QF based on the rates charged to WCU by Nantahala at any point in time, and it is the same formula approved by the Commission in previous avoided cost proceedings. No party challenged the avoided cost formula proposed by WCU. The Commission concludes that WCU's proposed Small Power Production Supplier Reimbursement Formula should be approved. Consistent with our conclusions in past proceedings, WCU should not be required to offer any long-term levelized rate options.

IT IS, THEREFORE, ORDERED as follows:

1. That PEC shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of 10-years and 15-years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. PEC shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity;

2. That Duke shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of 10-years and 15-years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Duke shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity;

3. That Dominion shall offer long-term levelized capacity payments and energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5-year, 10-year, and 15-year periods as standard options to (a) hydroelectric QFs owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric QFs fueled by trash or methane derived from landfills, hog waste, poultry waste, solar, wind, and non-animal forms of biomass contracting to sell 5 MW or less capacity. The standard levelized rate options of 10-years and 15-years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost

rates and other relevant factors or (2) set by arbitration. Dominion shall offer its standard 5-year levelized rate option to all other QFs contracting to sell 3 MW or less capacity. Dominion shall offer long-term levelized energy payments as an additional option for QFs rated at 100 kW or less capacity;

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

5. That a performance adjustment factor of 2.0 shall be utilized by both PEC and Duke for their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation;

6. That a performance adjustment factor of 1.2 shall be utilized by both PEC and Duke for their respective avoided cost calculations for all QFs in this proceeding, except hydroelectric facilities with no storage capability and no other type of generation;

7. That Duke's capacity rates used to calculate avoided capacity costs shall continue to be based on actual investment costs that would be avoided because of the existence of a QF, rather than on market data. Duke shall recalculate and file avoided capacity credits that include a value for capacity in 2005 and 2006;

8. That the sale of power by QFs at avoided cost rates does not convey the right to renewable energy credits or green tags;

9. That the variable energy rates established by the Commission in these biennial proceedings shall continue to be the "as available" avoided cost energy rates;

10. That capacity in excess of the contract capacity of standard rate QF generators must be consumed internally by the QF;

11. That PEC's proposed revision to its capacity credits is approved;

12. That no change to PEC's treatment of holidays that fall on the weekend is required;

13. That Duke's proposal to eliminate its current Option A set of on-peak and off-peak hours in Schedule PP is rejected; however, Duke shall be permitted to offer Option B as an additional option available to QFs;

14. That investigation of issues related to interconnection costs is inappropriate as a part of this proceeding;

15. That the rate schedules and standard contract terms and conditions proposed in this proceeding by PEC, Duke, and Dominion are approved except as otherwise discussed herein. The utilities shall file new versions of their rate schedules and standard contracts, in compliance with this Order, within 20 days after the date of this Order to be effective 10 days after their filing. The rate schedules and contracts shall go into effect 10 days after they have been filed unless specific objections as to the accuracy of the calculations or conformity to the decisions herein are filed within that 10-day period and a further order is issued;

16. That PEC, Duke, and Dominion shall each file supporting documentation showing the calculations made to arrive at their avoided cost rates, highlighting any additional changes required by this Order; and

17. That WCU's proposed Small Power Production Supplier Reimbursement Formula is reasonable and appropriate and WCU shall not be required to offer any long-term levelized rate options to QFs.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of September, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr092905.01

DOCKET NO. E-100, SUB 101

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Progress Energy Carolina, Inc.,	)	ORDER APPROVING,
et al. for Approval of "Model" Small	)	IN PART, PROPOSED
Generation Interconnection Standard	)	INTERCONNECTION
and Associated Application to Interconnect	)	STANDARD
and Interconnection Contract Forms	)	

BY THE COMMISSION: On June 4, 2004, Progress Energy Carolinas (Progress), Duke Power (Duke), and Dominion North Carolina Power (Dominion) jointly filed a proposed model small generator interconnection standard, application, and agreement. The proposed model interconnection standard would apply to parallel interconnection of single-phase small generation systems rated at 20 kW or less for residential customers and 100 kW or less for non-residential customers. This proposal would not only provide standardization of the interconnection criteria for safety and reliability, but would also provide a streamlining of the interconnection process.

On July 12, 2004, the Commission issued an Order allowing parties an opportunity to file written comments and reply comments on the utilities' proposal. The Commission noted that no party had requested that a full evidentiary hearing be convened, and stated that it would attempt to resolve all issues arising in this docket based on a record developed through the written comments filed by the parties.

Initial comments were filed by the Attorney General and the North Carolina Sustainable Energy Association (NCSEA). Reply comments were filed by the utilities, the Attorney General, and the Public Staff. A number of other individuals and businesses filed statements of position.

The proposed documents represent the result of a collaborative effort between representatives of Progress, Duke, Dominion, the NCSEA, and the North Carolina Solar Center.[1] Through the collaborative process most of the interconnection issues have been resolved. The utilities identified six issues upon which the parties could not reach agreement. The filed documents reflect the consensus of the group where reached as well as the utilities' proposed resolution of the outstanding issues. The NCSEA identified four additional issues which it believed should be resolved that were not addressed in the proposed documents.

The positions of the parties and the Commission's conclusions with respect to each of these ten issues is detailed below.

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[1] The Commission notes that similar efforts have been undertaken at the national level by the National Association of Regulatory Utility Commissioners (NARUC) and the Federal Energy Regulatory Commission (FERC). In October 2001, the FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) in Docket No. RM02-1 proposing to amend the open access transmission tariffs (OATTs) of its jurisdictional utilities to include standardized generator interconnection agreements and procedures. Comments received by the FERC indicated that a separate proceeding should be undertaken specifically to address interconnection for generators no larger than 20 MW. In August 2002, the FERC issued an ANOPR in Docket No. RM02-12 proposing standardized generator interconnection agreements and procedures for these small generators. In October 2003 NARUC published "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources" in response to the FERC proceeding. This document proposed a model standard based upon distributed generator interconnection agreements and procedures that had been developed in California, Texas, New York, and Ohio and purported to reflect the "best practices" from these states. The FERC issued a Notice of Proposed Rulemaking (NOPR) in Docket No. RM02-12 on July 24, 2003. A coalition of stakeholders, including NARUC, a group representing small generators, and others, worked during the ensuing months to reach consensus on modifications to the interconnection agreements and procedures included in the FERC NOPR. Final comments and proposed revisions were filed by the coalition on February 18, 2005. The FERC has not yet issued a final rule in this docket.

Redundant Isolation Device

Proposed Interconnection Standard

The utilities propose that each generator be installed with a clearly labeled manual load-break disconnect switch accessible to company personnel to isolate the generator from the transmission system. (Model Std. § 3.6)

Position of the Parties

The NCSEA argues in its comments that the proposed external disconnect switch (EDS) is unnecessary to protect utility line workers due to the presence of other required manual and automatic disconnect switches. The NCSEA states that national Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratories (UL) technical standards for distributed generation (DG) interconnection equipment contain requirements that the equipment disconnect automatically whenever the electric grid is de-energized. In addition the National Electric Code (NEC) requires interconnected systems to have manual disconnect switches inside the building near the main circuit breaker panel for most customer generators. The NCSEA further argues that an EDS will have minimal safety impact if line workers follow standard utility safety procedures to treat all lines as energized and ground both upstream and downstream sides of the circuit upon which they are working. Notwithstanding the NCSEA's objection, it states that it will accept the utilities' request for an EDS for non-residential generators. The NCSEA continues to argue, however, that the added expense of the switch is not justified for residential customers with small, inverter-based renewable energy systems, especially when the utilities can use the meter base as a way to disconnect the system with no additional expense to the customer.

The utilities in their reply comments note that the proposed interconnection standards are applicable to all types of single-phase generators and not just to generators that utilize an inverter. The utilities state that, contrary to the NCSEA's assertions, the requirement for a customer generator to install an EDS is not contrary to, but rather is consistent with, IEEE standards. The utilities argue that safety is paramount and elimination of the EDS could jeopardize safety in order to save the customer generator less than 1-2% of the installed cost of a small generation system. The utilities urge the Commission to reject the NCSEA's suggestion that the utility be required to remove a residential customer's meter in order to isolate a generator. The utilities argue that some residential customers are metered with other than self-contained metering and that for them pulling the meter will not disconnect service. In addition, removing the meter will not only disconnect the customer's generator from the local distribution system, it will disconnect the customer entirely, leaving the customer without electric service. Moreover, removing the meter serving the customer will not disconnect the generator from the wiring inside the meter base. Safe work practices require the isolation of a generator from the meter base before work may be safely done inside the base. Devices integral to the generator or inaccessible to utility personnel are of no use in isolating the generator. Lastly, the utilities note that an EDS is either required by state commission rules or orders or approved by the commissions in Arizona, Colorado, Florida, Hawaii, Idaho, Illinois, Kansas, Kentucky, Massachusetts, Missouri, New York, Ohio, Texas, Vermont, Virginia, Wisconsin, and Wyoming.

In its comments, the Public Staff expresses concern about potential safety issues that could arise if the meter base is used to disconnect the system. While a meter base could be used as a disconnect switch, it is a crude solution akin to pulling the plug out of the wall to shut off an appliance. Further, disconnecting via the meter base creates an electrical arc with the potential for causing a fire or burn injury. Thus, while the Public Staff would have preferred to have more information on the actual cost of installing an EDS, it recommends that the Commission find that the requirement that an EDS be installed is reasonable.

Discussion and Conclusions

The Commission concludes that the proposed EDS requirement is reasonable generally for the reasons set forth by the Public Staff.[1] The Commission is also persuaded by the utilities' arguments that requiring utility personnel to pull the meter base to disconnect the customer-owned generator is not a satisfactory solution in that it entirely disconnects the customer from the utility grid but does not disconnect the customer's generator from the meter base. The utilities state elsewhere in their comments that the incremental cost of adding an EDS is minimal – only two percent of the cost for a small residential 2 kW photovoltaic system. While the Commission is cognizant of the need to avoid unnecessarily imposing costs which might serve as barriers to the development of small distributed generation, safety for utility personnel and the public must be our paramount concern.

Costs Associated with Upgrades to the Transmission System

Proposed Interconnection Standard

The utilities propose that "[t]he Customer will bear all the cost of interconnection, including, but not limited to, the cost necessary to meet all technical and protection requirements." The utilities further propose to reserve the right "to require additional interconnection facilities to be furnished, installed, owned and maintained by the Company at the Customer's expense, if determined necessary by the Company." (Model Std. §§ 4.4, 4.4.1)

Position of the Parties

The NCSEA in its comments disagrees with the proposed Section 4.4 and Subsection 4.4.1 on the grounds that they are vague, ambiguous, and ill-defined and that they increase the uncertainty as to potential costs for the customer. The NCSEA proposes that Subsection 4.4.1 be deleted in its entirety and that the following revised language be substituted for Section 4.4 (additional language underlined):

> 4.4. Interconnect Cost: The Customer will bear all the cost of interconnection directly resulting from installation of a distributed generation system and not the result of otherwise appropriate system upgrades, including, but not limited to, the cost necessary to meet all technical and protection requirements.

The NCSEA contends that the utilities' concerns about not being required to bear the costs of interconnection are properly addressed because the revised Section 4.4 covers costs on the customer's side of the meter and the undisputed Subsection 4.4.2 covers costs on a utility's side of the meter.

The utilities in their reply comments object to the NCSEA's suggestion that the utilities in North Carolina would "manipulate the situation in a way that inflated costs and added time to review" and argue that the Commission should reject the changes and deletions recommended by

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[1] The Commission notes that the February 2005 small generator interconnection agreements and procedures submitted by the coalition in FERC Docket No. RM02-12 do not take a position on this issue, indicating only that the utility shall have access to the disconnect switch if such a switch is required by the State.

NCSEA. However, in an attempt to address the NCSEA's concerns, the utilities state that they will agree to the following revision to Subsection 4.4.1 (additional language underlined):

> 4.4.1. Interconnection Facilities: The Company reserves the right to require additional interconnection facilities to be furnished, installed, owned and maintained by the Company at the Customer's expense, if determined necessary by the Company, to address any power quality, reliability or safety issues caused by the Generator operation or connection to the Area EPS [Electric Power System].

The utilities argue that neither the utility nor its other customers should bear the costs resulting from the interconnection of a customer-owned generator to the utility's distribution grid. Those costs should be the responsibility of the party causing them and presumably benefiting from the interconnection – the owner of the generator. The customer will be charged only for those upgrades to the utility's system caused by the addition of the customer's generator. In the event the customer believes the costs of interconnecting facilities and Area EPS changes and upgrades proposed by the utility are improper, the customer has the option of discussing his concerns with the Public Staff and/or filing a formal complaint with the Commission.

The Attorney General in its comments supports the NCSEA's proposed changes, stating that they would improve the clarity and certainty of the allocation of costs between the customer generator and the utility. The proposed additional language in Section 4.4 places the responsibility for all costs directly caused by the customer generator on the customer generator, while placing the responsibility for other costs, such as those for system upgrades, upon the utility. With that clarification striking the appropriate balance in the allocation of costs, the proposed language of Section 4.4.1 needlessly introduces uncertainty for customer generators as to what costs to expect, and should thus be eliminated.

In its comments, the Public Staff argues that the language originally proposed by the utilities is so open-ended that it frustrates the entire purpose of the collaborative. The Public Staff agrees with the NCSEA's proposed modification to Section 4.4 and proposed deletion of Subsection 4.4.1. These changes should prevent the utilities from bearing costs which they did not cause and reduce customers' potential liability for unknown costs.

Discussion and Conclusions

As noted by several of the parties, a guiding principle in this debate is that a customer generator, and not the utility or its other customers, should be held responsible for the cost of any upgrades or improvements, both on the customer's and the utility's sides of the meter, which are required to accommodate the interconnection request if such upgrades would not be necessary but for the requested interconnection. This is consistent with the position taken by the Commission in various proceedings before the FERC. The language of the proposed interconnection standard appears to support this position; the parties in their comments have proposed changes to the original language that would clarify any uncertainty in the costs ultimately borne by the customer generator.

Implicit in Section 4.4 is the requirement that some entity must determine what costs are necessary to accommodate the requested interconnection. The Commission concludes that the party in the best position to make this determination is the utility to which the customer generator is requesting to interconnect. The Commission further concludes that the utilities' proposed additional language better clarifies the costs that should be borne by the customer and that Section 4.4 should be revised as follows:

> 4.4. Interconnect Cost: The Customer will bear all the cost of interconnection, including, but not limited to, the cost necessary to meet all technical and protection requirements to address any power quality, reliability or safety issues caused by the Generator's operation or connection to the Area EPS.

With this change, the Commission agrees with the NCSEA and the Attorney General that Subsection 4.4.1 is unnecessary and should be deleted. The language of revised Section 4.4 gives the utilities the right to require the installation of facilities they reasonably determine to be necessary to address issues caused by the customer generator's interconnection or operation consistent with the other provisions of the interconnection standard as approved by the Commission.

The language of the proposed Section 4.4.2, which the parties may wish to consider consolidating into Section 4.4 with the deletion of Subsection 4.4.1, recognizes that the customer is also responsible for the cost of any necessary changes or upgrades to the Area EPS required to accommodate the interconnection request. It is anticipated, however, that no changes or upgrades will be required where a proposed generator successfully passes the Impact Screens. The Commission will consider complaints about any interconnection costs sought to be imposed on a customer generator on a case-by-case basis.

Liability and Insurance Requirements

Proposed Interconnection Standard

The utilities propose that "[t]he Customer is liable and shall bear the cost of resolving any power quality, reliability or safety issues or problems caused by the Generator operation or connection to the Area EPS." In addition, "[t]he Customer shall obtain and retain ... comprehensive general liability insurance with limits of at least $500,000 per occurrence which protects the Customer from claims for bodily injury and/or property damage. This insurance shall be primary for all purposes." (Model Std. §§ 4.6, 4.7)

Position of the Parties

The NCSEA argues in its comments that proper installation of an IEEE/UL approved generator will result in safe operation and obviate the requirement for additional consumer insurance. Innovations in power electronics have made risks of personal injury or property damage inconsequential, and existing legal mechanisms such as mutual indemnification and contractual limitations on liability are the appropriate way to address utility concerns. The NCSEA has proposed "limitation of liability" language to be added to Section 4.6 and a new "mutual indemnification" provision to be added after Section 4.6. The NCSEA notes that such a mutual indemnification has been proposed in the NARUC model interconnection rules and that the Texas Public Utilities Commission, in adopting such a provision, concluded, "Mutual indemnification is the most reasonable approach because it required each party to bear the consequences of its negligence."

In support of a reduced insurance requirement, the NCSEA argues that the practical effect of insurance requirements is either to discourage customers from generating their own electricity and to stifle the market for small-scale renewable generation or to encourage customers to install systems without informing the utility. The NCSEA states the requirement for additional insurance has been a consistent criticism of the utilities' existing solar photovoltaic (PV) riders from potential customers and installers of solar PV systems. Not only would the proposed requirement for additional insurance potentially exceed any cost savings or revenues anticipated by a small renewable generator, it may not even be available for residential customers in North Carolina. The proposed requirement may also be problematic for self-insured entities in North Carolina, such as government agencies and large businesses. The NCSEA notes that many of the states that have addressed the insurance issue, often in net metering dockets, have explicitly rejected any requirement for additional insurance. The Tennessee Valley Authority does not require additional insurance for customers selling renewable energy to the electric grid in its green power program similar to NC GreenPower. Other states, including Kentucky and Virginia, require residential customer generators to have a standard $100,000 homeowner's policy and non-residential customer generators at least a $300,000 commercial liability policy. The NCSEA recommends that the Commission adopt a similar insurance requirement for small generator interconnections in North Carolina.

The utilities in their reply comments urge the Commission to reject the NCSEA's proposed changes, arguing that to do so would "inappropriately shield[] the generator owner from responsibility for damages that may result from the installation and operation of the grid-connected generator" and "shift that financial exposure to the utility and its other customers." The utilities state that the NCSEA proposes a lengthy mutual indemnification provision in lieu of the liability clause in Section 4.6 of the proposed interconnection standards and argue that such "indemnification language is of no value if the indemnitor does not have the resources to honor the indemnification obligation." With regard to the NCSEA's proposed reduction in the insurance requirement, the utilities argue that their risk management analyses demonstrate that the requirements should be much higher than the $500,000 amount included in the proposed standard and that they agreed to the proposed $500,000 amount as a compromise with the NCSEA. As with the issues regarding the liability provisions, the utilities are very concerned that further reducing the liability insurance requirements will expose them and their customers to financial risks that are a direct result of the interconnection of the generators and are more appropriately borne by the grid-connected generators. If the Commission were to consider any further reduction in liability requirements, then it should also include a provision exempting the utility from any liability to the customer or others associated with the grid-connected generator, similar to provisions adopted by several other states. Lastly, the utilities state that they are agreeable to the acceptance of self-insurance in lieu of additional insurance when the customer has a self-insurance program established in accordance with commercially acceptable risk management practices that provides coverage at a level of at least the amount otherwise required in the interconnection standard. When a self-insurance situation occurs, the necessary language would be added to the interconnection agreement as an alternative to the insurance coverage.

The Attorney General in its comments agrees with the NCSEA's recommendations. The Attorney General states that the Commission's overarching goal should be to establish standards that protect the safety of utility company employees and the integrity of the grid. The Commission should be able to do so by relying upon the provisions of the NEC, the safety standards of such organizations as IEEE and UL, and the safety guidelines that have proven to be successful in the more than thirty-five states that have adopted net metering rules. Once the safety goal is met, liability insurance becomes much less a consideration, and the Commission can set the required levels of insurance such that the costs will not become an unnecessary barrier to customer generators.

In its comments, the Public Staff states that after studying this issue in the net metering docket (Dkt. No. E-100, Sub 83) and in the instant docket, it believes that the NCSEA's positions on insurance requirements and indemnification are reasonable. The utilities have not been able to produce a record of safety-related insurance claims resulting from non-utility generators, and there have been no reports of any problems in North Carolina during the existence of the PV Rider. Moreover, it seems unreasonable for the utilities to require indemnification without being responsible for any damage or injury they caused.

Discussion and Conclusions

The Commission agrees that the proposed insurance requirements present an unnecessary barrier to entry for small generators. The Commission has set safety first with regard to the requirements for interconnection and operation of customer generators. As the Attorney General suggests, liability insurance now becomes much less a consideration, and the Commission can set the required levels of insurance such that the costs will not become an unnecessary barrier to customer generators. The Commission, therefore, concludes that the NCSEA's recommendation should be adopted and that a residential customer generator should be required to have in effect a standard homeowner's insurance policy with coverage in the amount of at least $100,000, and that a non-residential customer generator should be required to have in effect a commercial liability insurance policy with limits not less than $300,000.

The Commission further concludes that it is reasonable to include limitation of liability and mutual indemnification provisions in the model interconnection standard. The Commission notes that the language proposed by the NCSEA is that set forth in the NARUC Model, and concludes that the following language based upon the February 2005 coalition submission to the FERC should be adopted instead:

> Limitation of Liability: Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, special, incidental, consequential, or punitive damages of any kind.
>
> Indemnification: The parties shall at all times indemnify, defend and save the other party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties, arising out of or resulting from the other party's action or inaction of its obligations hereunder on behalf of the indemnifying party, except in cases of gross negligence or intentional wrongdoing by the indemnified party.

Lastly, the Commission concludes that the first sentence of Section 4.6 proposed by the utilities should be deleted. This sentence is now redundant because the revised Section 4.4 requires the customer generator to bear all costs necessary to address any power quality, reliability or safety issues caused by the generator operation or connection to the Area EPS. The second sentence of Section 4.6, which relates to access to and operation of the generator, should be retained and the section renamed to reflect the customer generator's obligations.

Application and Review Fees

Proposed Interconnection Standard

The utilities propose that residential service customers pay an interconnection application fee of $100 and that non-residential customers pay a fee of $500. (Model Std. § 4.10)

Position of the Parties

The NCSEA argues in its comments that costs to generators for application and review should be as low as possible to encourage an expeditious process while at the same time providing reasonable compensation for the minimal work required. While acknowledging that commercial units should pay limited application fees, the NCSEA believes that there should be no fee to process applications for customer generator units 20 kW or less that pass the proposed technical screens and that the fee for units between 20 kW and 100 kW should be no more than $100. The NCSEA believes that this is reasonable because all pre-certified units of this minimal size will require little, if any, analysis to be approved for interconnected operation. In support of its proposal, the NCSEA includes a list of fees approved in other states.

The utilities in their reply comments argue that the NCSEA's proposed elimination and reduction of fees should be rejected because it would not allow recovery of the costs associated with reviewing and processing the request for interconnection, shifting those costs to the utility and its other customers. The utilities note that the NCSEA's comments demonstrate a wide variation in fees allowed in other states. Moreover, the utilities note that the NCSEA incorrectly states that there is no fee in Florida when, in fact, the application fee for Progress Energy Florida, as approved by the Florida Public Service Commission, is $95.

In its comments, the Attorney General notes that the interconnection of each new customer generator will create at least some additional administrative work for the utility. The Attorney General believes that each customer generator should pay a fair administrative fee to reimburse the utility for its increased administrative costs and recommends that the Commission request cost data from the utilities for use in establishing uniform application fees.

The Public Staff recommends in its comments that the Commission require the utilities to provide cost studies justifying the $100 and $500 fees. If these cost studies justify the charges, the Public Staff believes the proposed fees should be approved. The utilities should not be required to bear costs they do not cause.

Discussion and Conclusions

The Commission agrees with the NCSEA that unnecessary barriers to the development of small renewable generation should be eliminated. For example, the Commission supported a 2004 amendment to the Public Utilities Act which eliminated the requirement for newspaper publication for small photovoltaic systems. Consistent with the earlier stated principle on cost causation, however, the customer generator should be required to reimburse the utility for the costs likely to be incurred to review an interconnection request. Such costs should not be shifted to the utility or its other customers. In addition, the imposition of at least a nominal fee should reduce the burden to the utilities by limiting interconnection requests to serious inquiries only.

No evidence has been provided to justify the amount of the fees proposed by the utilities, however, and the Attorney General and the Public Staff have recommended that the Commission require the submission of such data. Rather than adopt particular fees at this time, the

Commission encourages the parties to continue negotiation on this issue and to reconsider the proposed application fee structure, including the adoption of an alternative fee arrangement such as crediting some portion of the application fee paid by a consumer generator against future costs.[1] Absent consensus on this issue, the utilities should be required to file cost studies justifying fees not exceeding those originally proposed in this docket.

Distribution Circuit Saturation Point

Proposed Interconnection Standard

The utilities propose a limit on area electric power system (Area EPS) circuit level saturation, or the cumulative total of the maximum rated output of all interconnected generation, of no more than 2% of rated circuit capacity. The utilities propose fixed ratings for circuits based on the circuit voltage, leading to varying percentages of rated capacity from 30 kW on a circuit of 10 kV or less to 100 kW on a circuit of 20 kV or greater. (Model Std. § 6.1)

Position of the Parties

The NCSEA states in its comments that the thresholds for the circuit saturation screen proposed by the utilities are unreasonably low. The NCSEA proposes that a screen of 10% of circuit peak load, plus a 5% "bonus" for solar electric systems, should be adopted.

The utilities in their reply comments argue that the interconnection of customer-owned generation to the utility's electric distribution system may cause significant power quality, reliability and safety concerns. The utilities state that they carefully review the interconnection of generators to their distribution systems to identify and incorporate measures to address any potential concerns. The utilities argue that the approval of the proposed screening criteria will not create a roadblock to the interconnection of small generators; the proposed limitations do not mean that additional generation cannot be interconnected, but rather only that additional review will be required when the limitation on a specific circuit is reached. If the saturation level for a specific circuit is reached, the utilities state that they will further review the interconnection request and its impact on the specific circuit involved. For small generators, this review should not be time consuming. The utilities note that the proposed criteria will allow up to approximately 200 MW of small generation to be interconnected to the utilities' distribution systems under the expedited procedures with no additional studies required. If, as new generators are interconnected, the proposed saturation points are reached on individual circuits, the utilities commit to review the criteria and consider revisions to the standards.

In its comments, the Public Staff states that it is reluctant to specify how the utilities should operate their systems. Nonetheless, the utilities should be willing to review proposals on a case-by-case basis in some circumstances. The Public Staff notes that Section 8.3 dealing with Impact Screens allows the customer to request the utility to reconsider an application outside the scope of the standard. The Public Staff recommends that the Commission provisionally approve this provision but require the utilities to file semiannual reports detailing how many interconnection requests have been denied for exceeding the limits, how many requests have been reconsidered pursuant to section 8.3, and any other information regarding this issue. After

[1] The Commission notes that the February 2005 small generator interconnection agreements and procedures submitted by the coalition in FERC Docket No. RM02-12 include an application fee equal to the greater of (1) $0.50 per nameplate kVA rating, (2) $100 for single-phase generators no larger than 25 kVA, or (3) $500 for three-phase generators and single-phase generators larger than 25 kVA. It is not clear whether an application fee is required for an inverter-based generator 10 kW or smaller.

sufficient experience has been gained, perhaps after three years, the Commission should request the parties to file comments on the efficacy of this standard.

Discussion and Conclusions

The Commission concludes that the Public Staff's recommendation is reasonable and that the circuit level saturation limits proposed by the utilities should be provisionally approved.[1] The Commission notes that the utilities in their reply comments state that any application to interconnect a generator which would cause the saturation limit on a distribution circuit to be exceeded may be reviewed on a case-by-case basis. The utilities have further committed to reconsider the saturation limits, if necessary, after gaining additional experience with small generator interconnections. The Commission, therefore, will require the utilities to file semiannual reports detailing the number of interconnection requests approved and denied and the reasons for any denial.

Need for Separate Interconnection Agreement

Proposed Interconnection Standard

The utilities propose that a customer generator sign an interconnection agreement after the completion of the interconnection application process and the impact screens. (Model Std. § 8.4)

Position of the Parties

The NCSEA in its comments does not dispute the need for a separate interconnection agreement for commercial customer generators, but it believes that the application and agreement should be the same document in the case of residential customers. The NCSEA states that it would like to work further with the utilities and the Public Staff to determine if this issue could be resolved.

The utilities in their reply comments argue that the purpose of the interconnection agreement is to establish the terms and conditions for the interconnection of the small generator to the utility's distribution system, while the purpose of the one-page application is simply to collect the basic data required by the utilities to review the proposed interconnection. The specific information applicable to an individual customer generator is not known by the utility until after the application is submitted. The data included in the application is used to evaluate the technical feasibility of the interconnection and to develop the interconnection agreement. Assuming the requested interconnection meets the interconnection standards, the utility and the customer generator will then execute the interconnection agreement. The utilities state that the norm in most other states is also to separate the application from the interconnection agreement. The separate one-page application is not unreasonable and imposes no significant burden on the generator seeking interconnection.

In its comments, the Public Staff states that it is willing to work with the parties to resolve this issue and recommends that the Commission require a status report from the parties 60 days from the date of an order in this matter.

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[1] The Commission notes that the February 2005 small generator interconnection agreements and procedures submitted by the coalition in FERC Docket No. RM02-12 allow the aggregated generation, including the proposed generator, on a circuit to not exceed 15 percent of the line section annual peak load.

Discussion and Conclusions

The Commission agrees with the NCSEA that the separate interconnection agreement, at least in the case of residential consumer generators, tends to unnecessarily complicate the interconnection process. The addition of a signature line to the one-page application indicating acceptance by the utility may be sufficient to render superfluous the separate interconnection agreement, which appears to restate many of the provisions in the proposed standard.[1] The NCSEA and the Public Staff have requested an opportunity to continue to negotiate with the utilities in an attempt to reach final consensus on this issue. The Commission concludes that the parties' request for further negotiation on this issue should be granted. The parties should focus their further discussions on simplifying, to the greatest extent reasonably possible, the application and interconnection process for potential small generators.

Three-phase Generators

Proposed Interconnection Standard

The model interconnection standard proposed by the utilities is applicable only to single-phase generators.

Position of the Parties

The NCSEA notes in its comments that a technical issue that was set aside in the negotiations between the NCSEA and the utilities was the inclusion of three-phase generation systems. The NCSEA contends that three-phase generation systems should be included in the interconnection standards. It points out that this is an important issue to small farms and commercial customers who would require three-phase service to accommodate larger generation systems. In light of the vast potential for farm-based generation in North Carolina, particularly from hog and poultry farms in the east, the NCSEA requests that the Commission seek additional comment on this issue so it can be resolved quickly and in a way that allows farmers to fully participate in NC GreenPower and in other distributed generation opportunities.

The utilities in their reply comments state that the proposed interconnection standard is limited to single-phase generators consistent with the agreement the utilities reached with the NCSEA early in the collaborative process. The utilities state that the current national product testing standards do not test three-phase generators for one of the most common outage scenarios. The utilities further state that they agreed to consider revising the proposed interconnection standard after the UL standard is revised and aligned with IEEE testing standards currently under development. Although not included in the proposed interconnection standard, the utilities will evaluate any request for interconnection by a three-phase customer generator to determine whether it would have an adverse impact on the distribution system and, if so, what additional measures might be required. The only impact of excluding three-phase generators from the currently proposed streamlined interconnection standards is that the three-phase generators will not automatically pass the "plug and play" screen, but will require review before the utility agrees to the interconnection. This process in no way inhibits three-phase generators participating in NC GreenPower. Lastly, the utilities argue that the NCSEA's request for additional comment on this issue is premature and would not be productive at this time. The

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[1] The Commission notes that the February 2005 small generator interconnection agreements and procedures submitted by the coalition in FERC Docket No. RM02-12 contemplate a separate interconnection agreement except in the case of inverter-based generators 10 kW or smaller.

utilities have already agreed to address the issue of three-phase generators, but only after UL and IEEE complete their reviews and establish appropriate national standard testing requirements.

In its comments, the Public Staff states that it believes that this is another issue that might be resolved through additional discussion and negotiation rather than through additional comment. It appears to the Public Staff that resolution of this matter is vital to the ability of small farms generating electricity from hog and poultry waste to participate in NC GreenPower. The Public Staff is willing to work with the parties to resolve this issue and proposes that the Commission require a status report from the parties 60 days from the date of an order in this matter.

Discussion and Conclusions

The Commission agrees with the Public Staff that additional comment by the parties on this issue at this time would not likely be productive. Considerable consensus has been reached in drafting the currently proposed interconnection standard, and it stands as a significant accomplishment by the parties. The interconnection standard proposed in this docket does not preclude the interconnection of any non-utility electric generator. The principles set forth in this Order regarding safety, cost causation, and the elimination of unnecessary complexity should equally apply to the review of interconnection requests by any generator. The inclusion of three-phase generators, however, is left as an issue for future negotiation among the parties.

Tariff Issues

Proposed Interconnection Standard

The model interconnection standard proposed by the utilities does not address revisions to other tariffs or riders.

Position of the Parties

The NCSEA states in its comments that one of the most significant issues left unaddressed by the informal negotiations between the parties was the need for a revised tariff or rider to respond to the significant non-technical regulatory barriers facing potential customer generators. The NCSEA argues that unreasonable backup and standby tariffs, local distribution system access pricing issues, transmission and distribution tariff constraints, and exit fees are some of the factors which can stymie development of distributed generation even with good interconnection technical standards. The NCSEA states that it has proposed a draft Small Generator Interconnection Tariff to the utilities and requests that the Commission ask for additional comment on this issue so it can be resolved quickly and in a way that allows distributed generation, and especially renewable energy, to flourish in North Carolina.

The utilities in their reply comments note that the proposed interconnection standard and procedures only address the technical issues relating to the physical interconnection of customer generators. The utilities disagree with the NCSEA's request that the Commission seek additional comments on rate and tariff issues in this proceeding, arguing that such issues regarding rates are more appropriately addressed elsewhere. The utilities currently have Commission-approved rates and/or tariffs applicable to the purchase and sale of electricity between customer-owned small power producer and qualifying facilities and the interconnected utility. A proceeding to determine the rates to be paid by the utilities for the purchase of electricity from qualifying facilities and small power producers is pending before the Commission in Docket No. E-100, Sub 100.

In its comments, the Public Staff states its belief that this is another issue that might be resolved through additional discussion and negotiation rather than through additional comment. The Public Staff states that it is willing to work with the parties to resolve this issue and recommends that the Commission require a status report from the parties 60 days from the date of an order in this matter.

Discussion and Conclusions

The Commission agrees with the NCSEA that unreasonable costs imposed on an operating customer generator other than those at issue in the proposed standard can stifle its development as easily as unreasonable technical requirements. A parallel effort, therefore, should be undertaken by the parties to consider whether amendments are necessary to formerly approved tariffs and rate riders that would be otherwise applicable to small customer-owned generation. In addition, the utilities' existing tariffs and riders should be modified, as necessary, to conform to the provisions approved in the interconnection standard.

Green Tags

Proposed Interconnection Standard

The model interconnection standard proposed by the utilities does not address the ownership of renewable energy credits, or "green tags."

Position of the Parties

The NCSEA requests in its comments that the interconnection agreement or the tariffs also address the issue of ownership of renewable energy credits, or "green tags." A renewable generator may attempt to use this mechanism to realize added value for its generation by separately selling the green tags to interested consumers. The NCSEA cites a delay of several months to one potential NC GreenPower suppler while negotiating with an electric cooperative over ownership of the green tags. NCSEA requests that the Commission address this issue quickly to reduce uncertainty on the issue.

The utilities in their reply comments argue that the NCSEA is again reaching beyond the scope of this proceeding in attempting to interject questions regarding the ownership of green tags. The ownership of green tags is an issue related to the sale of energy by a renewable generator, not physical interconnection to the grid. Any issue related to ownership of green tags should be addressed in the contractual arrangement regarding the sale of energy between the renewable generator and the purchaser of that energy. While there may be issues regarding cooperatives, which are not regulated by the Commission, there is no dispute or uncertainty regarding the treatment of green tags associated with energy delivered to the grid by renewable generators under NC GreenPower. The utilities state that they have acknowledged "from day one" that the green tags associated with energy delivered to the grid under NC GreenPower will flow to NC GreenPower. The Commission, therefore, should take no action in this proceeding, which is focused solely on interconnection criteria, on the issue of green tags.

In its comments, the Attorney General agrees that the Commission should address this issue, noting, however, that it might be more appropriate to do so in the NC GreenPower docket (Dkt. No. E-100, Sub 90), in which a larger number of stakeholders are participants.

The Public Staff states in its comments that it is unaware of any actual case or controversy involving the green tags issue that has been brought before the Commission. The

Public Staff notes that, while this is an issue of importance, it is not ripe for adjudication at this juncture. The proper time for Commission action is when a complaint is properly filed with the Commission.

Discussion and Conclusions

The Commission agrees with the NCSEA that the issue regarding ownership of renewable energy credits, or green tags, needs to be resolved to enable renewable generators to more easily interconnect with and sell power to the grid. As stated by the other parties, however, this is not strictly an interconnection issue and is best resolved in another, more appropriate, docket. The Commission notes that this issue has been raised in the pending avoided cost docket (Dkt. No. E-100, Sub 100) and intends to address the issue in that docket.

Interconnection of Larger "Small" Generators

Proposed Interconnection Standard

The model interconnection standard proposed by the utilities is applicable only to small generators rated at 20 kW or less for residential customers and 100 kW or less for non-residential customers.

Position of the Parties

While acknowledging that the parties agreed in their discussions to focus the currently proposed interconnection criteria on generators rated at 20 kW or less for residential customers and 100 kW or less for non-residential customers, the NCSEA suggests in its comments that future interconnection discussions should be held to focus on generators up to 20 MW.

The utilities in their reply comments note that the impact of connecting a 20 MW generator to the utilities' distribution systems can be substantial. An interconnection request for a generator of that size would require a comprehensive, detailed study to evaluate that impact and to determine appropriate interconnection requirements. The utilities believe that it is premature to jump to a discussion of the parameters of potential future deliberations at this time. The issues at hand regarding the interconnection of small generators should be resolved first. Upon completion of this proceeding and establishment of the small generator interconnection standards, the utilities state that they would consider the procedures and criteria for interconnection of larger customer-owned generation. The utilities urge the Commission to take no action at this time regarding consideration of additional criteria for larger customer-owned generators.

Discussion and Conclusions

This Order resolves many of the outstanding issues related to small, single-phase generator interconnections. The Commission urges the parties to continue to work together to reach consensus on the remaining issues for the interconnection of small generators before trying to standardize the interconnection of larger generators. As stated earlier, the utilities will currently review interconnection requests by larger generators on a case-by-case basis, and the general principles established in this Order should apply equally in such instances.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed model small generator interconnection standard, application, and agreement, as well as the utilities' existing tariffs and riders, shall be revised consistent with the decisions in this Order;

a. That a customer generator shall be required to install a clearly labeled manual load-break disconnect switch accessible to company personnel;

b. That a customer generator shall be required to bear all the cost of interconnection, including, but not limited to, the cost necessary to meet all technical and protection requirements to address any power quality, reliability or safety issues caused by the customer generator's operation or connection to the area electric power system;

c. That a residential customer generator shall be required to have in effect a standard homeowner's insurance policy with coverage in the amount of at least $100,000, and that a non-residential customer generator shall be required to have in effect a commercial liability insurance policy with limits not less than $300,000; and

d. That Section 4.6 of the model interconnection standard shall be revised and that provisions shall be added regarding limitation of liability and mutual indemnification as stated herein;

2. That the parties shall seek to reach consensus through further negotiation on the amount of the application fees and the need for a separate interconnection agreement, particularly with regard to residential customer generators or inverter-based generators;

3. That the utilities shall file a status report within 60 days of the date of this Order on their further efforts to reach consensus and shall include (1) an updated model interconnection standard, application, and agreement revised consistent with this Order, and (2) cost studies justifying the proposed application fees absent consensus on that issue.

4. That each utility shall file a report by October 1, 2005, and every six months thereafter, providing detailed information regarding (1) any interconnection requests, including the type and size of the generator, the impact on the distribution circuit, whether the proposed generator passed the Impact Screens, and the status of the interconnection request; and (2) any claims for personal injury or property damage caused by the interconnection or operation of a customer generator; and

5. That the utilities shall promptly review all of their tariffs and riders that might be applicable to a customer generator applying for interconnection and parallel operation, including, for example, tariffs for purchase of energy from renewable generators and riders for the sale of stand-by generation service, to determine whether their applicability remains appropriate for small generators and shall file amendments or new tariffs or riders, as appropriate, in separate company-specific dockets not later than 90 days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of March, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Sw032205.01

DOCKET NO. E-100, SUB 101

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Progress Energy Carolina, Inc.,	)	
et al. for Approval of "Model" Small	)	
Generation Interconnection Standard	)	ERRATA ORDER
and Associated Application to Interconnect	)	
and Interconnection Contract Forms	)	

BY THE COMMISSION: The Commission finds good cause to issue this Errata Order amending its March 22, 2005, Order Approving, In Part, Proposed Interconnection Standard issued in the above-captioned docket to indicate that Commissioner Kerr did not participate in the decision.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of March, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Sw032805.01

DOCKET NO. E-100, SUB 101

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Progress Energy Carolina, Inc.,	)	
et al. for Approval of "Model" Small	)	ORDER APPROVING
Generation Interconnection Standard	)	REVISED INTERCONNECTION
and Associated Application to Interconnect	)	STANDARD, APPLICATION,
and Interconnection Contract Forms	)	AND AGREEMENT

BY THE COMMISSION: On June 4, 2004, Progress Energy Carolinas (Progress), Duke Power (Duke), and Dominion North Carolina Power (Dominion) jointly filed a proposed model small generator interconnection standard, application, and agreement. The proposed model interconnection standard would apply to parallel interconnection of single-phase small generation systems rated at 20 kW or less for residential customers and 100 kW or less for non-residential customers. This proposal would not only provide standardization of the interconnection criteria for safety and reliability, but would also provide a streamlining of the interconnection process.

The initial documents represented the result of a collaborative effort by representatives of Progress, Duke, Dominion, the North Carolina Sustainable Energy Association (NCSEA), and the North Carolina Solar Center. Through the collaborative process, most of the interconnection issues were resolved.

On March 22, 2005, after considering written initial and reply comments filed by the parties, the Commission issued its Order Approving, In Part, Proposed Interconnection Standard deciding most of the unresolved issues. In its Order, the Commission required the parties to seek to reach consensus through further negotiation on certain remaining issues and required the utilities to file a status report within 60 days on such efforts. The Commission further ordered the utilities to promptly review all of their tariffs and riders that might be applicable to a customer generator applying for interconnection and parallel operation, including, for example, tariffs for purchase of energy from renewable generators and riders for the sale of stand-by generation service, to determine whether their applicability remains appropriate for small generators and to file amendments or new tariffs or riders, as appropriate, in separate company-specific dockets not later than 90 days from the date of that Order.

On May 23, 2005, the utilities jointly filed a status report and revised model interconnection standard. With the filing of their status report, the utilities requested an extension of time within which to file the proposed tariff revisions until 60 days after the Commission's order approving the revised model interconnection standard.

By Chair Order dated June 14, 2005, the Commission continued the filing date for proposed tariff revisions pending further order of the Commission.

The revised model interconnection standard incorporates the decisions made by the Commission in its March 22, 2005 Order. In addition, as reflected in Section 4.12 of the revised model interconnection standard, the parties agreed through further negotiation that residential service customers should be required to pay an interconnection application fee of $100 and that the fee for non-residential customers should be reduced from $500 to $250. The parties have further agreed on the need for a separate interconnection agreement, even in the case of residential customer generators with inverter-based generators. The parties have agreed that during initial negotiations with a potential customer generator, the utility will send the potential customer a copy of the model interconnection standard and blank copies of the application and interconnection agreement, thereby giving the customer generator a copy of the documents early in the interconnection process.

The only remaining unresolved issue relates to Section 4.4 of the revised model interconnection standard. In its March 22, 2005 Order the Commission, after carefully considering the positions of the parties, ordered that Section 4.4 of the model interconnection standard be rewritten as follows:

> 4.4. Interconnect Cost: The Customer will bear all the cost of interconnection, including, but not limited to, the cost necessary to meet all technical and protection requirements <u>to address any power quality, reliability or safety issues caused by the Generator operation or connection to the Area EPS</u>.

With this change, the Commission found that Subsection 4.4.1 was unnecessary and should be deleted. The Commission further stated that the parties may consider consolidating into Section 4.4 the language of the proposed Subsection 4.4.2, which recognized that the customer is also responsible for the cost of any necessary changes or upgrades to the Area EPS required to accommodate the interconnection request.

Section 4.4 of the revised model interconnection standard, as proposed by the utilities, provides as follows:

> 4.4. Interconnect Cost: The Customer will bear all the cost of interconnection on the Customer's side of the point of interconnection as well as necessary changes or upgrades to the Area EPS including, but not limited to, the cost necessary to meet all technical and protection requirements to address any power quality, reliability or safety issues caused by the Generator operation or connection to the Area EPS.

The underlined language is proposed in addition to that included in the Commission's March 22, 2005 Order in order to incorporate former Subsection 4.4.2. The Commission finds that the additional language proposed by the utilities, which is unopposed by the NCSEA, is reasonable and should be approved. The original model interconnection standard addressed the obligations with respect to the customer's side of the meter and the utility's side of the meter in separate subsections. In consolidating the obligations of the former Subsection 4.4.2 into the new Section 4.4, the language proposed by the utilities provides a helpful clarification.

The NCSEA objects, however, to the "but not limited to" phrase, arguing that the inclusion of this "open ended phrase ... is unnecessary and throws the certainty we are looking for out the window."[1] The Commission agrees that the intent of Section 4.4 was to impose upon the customer generator only the cost of those changes necessary "to meet all technical and protection requirements to address any power quality, reliability or safety issues caused by the Generator operation or connection to the Area EPS." This comports with the change previously proposed by the utilities to Subsection 4.4.1 of the initial model interconnection standard.[2] The Commission, therefore, finds that the phrase "including, but not limited to, the cost necessary" should be deleted and that Section 4.4 should be approved as follows:

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[1] The Commission notes that the "but not limited to" phrase was included in Section 4.4 of the initially proposed model interconnection standard. In the NCSEA's comments on the original proposal, it requested that certain additional language be added to this Section, but did not object to the inclusion of the "but not limited to" phrase at that time. Specifically, the NCSEA proposed in its initial comments that Subsection 4.4.1 be deleted in its entirety and that the following revised language be substituted for Section 4.4 (additional language underlined):

> 4.4. Interconnect Cost: The Customer will bear all the cost of interconnection directly resulting from installation of a distributed generation system and not the result of otherwise appropriate system upgrades, including, but not limited to, the cost necessary to meet all technical and protection requirements.

[2] The utilities, in an attempt to address the NCSEA's concerns, had agreed to the following revision to Subsection 4.4.1 (additional language underlined):

> 4.4.1. Interconnection Facilities: The Company reserves the right to require additional interconnection facilities to be furnished, installed, owned and maintained by the Company at the Customer's expense, if determined necessary by the Company, to address any power quality, reliability or safety issues caused by the Generator operation or connection to the Area EPS [Electric Power System].

4.4. Interconnect Cost: The Customer will bear all the cost of interconnection on the Customer's side of the point of interconnection as well as necessary changes or upgrades to the Area EPS to meet all technical and protection requirements to address any power quality, reliability or safety issues caused by the Generator operation or connection to the Area EPS.

As stated by the Commission in its March 22, 2005 Order, a customer generator, and not the utility or its other customers, should be held responsible for the cost of any upgrades or improvements, both on the customer's and the utility's sides of the meter, which are required to accommodate the interconnection request if such upgrades would not be necessary but for the requested interconnection. The language of the proposed interconnection standard has always appeared to support this position; the parties in their comments and in the revised model interconnection standard have proposed changes to the original language that would clarify any uncertainty in the costs ultimately borne by the customer generator. The Commission, however, will continue to stand ready to consider complaints about any interconnection costs sought to be imposed on a customer generator on a case-by-case basis.

Lastly, the Commission concludes that the utilities' request for an extension of time to file amendments to tariffs and rate riders based upon the final approved interconnection standard, application, and agreement should be granted.

IT IS, THEREFORE, ORDERED as follows:

1. That the revised model small generator interconnection standard, application, and agreement shall be approved as stated herein; and

2. That the utilities shall promptly review all of their tariffs and riders that might be applicable to a customer generator applying for interconnection and parallel operation, including, for example, tariffs for purchase of energy from renewable generators and riders for the sale of stand-by generation service, to determine whether their applicability remains appropriate for small generators and shall file amendments or new tariffs or riders, as appropriate, in separate company-specific dockets on or before September 6, 2005.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of July, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Ah070605.04

Chair Jo Anne Sanford and Commissioners Sam J. Ervin, IV and Howard N. Lee did not participate in this decision.

DOCKET NO. E-100, SUB 102

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Investigation of Integrated Resource	)	ORDER APPROVING
Planning in North Carolina – 2004	)	INTEGRATED RESOURCE PLANS

BY THE COMMISSION: North Carolina General Statute 62-110.1(c) requires the North Carolina Utilities Commission (Commission) to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. This includes (1) the Commission's 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 the generating plants; (4) arrangements for pooling power to the extent not regulated by the Federal Power Commission (now the Federal Energy Regulatory Commission, or the FERC); and (5) other arrangements with other utilities and energy suppliers.

The purpose of this requirement is "to achieve maximum efficiencies for the benefit of the people of North Carolina." The statute requires the Commission to develop a plan for the future requirements for electricity for North Carolina or the area served by a utility and to consider its analysis in acting upon any petition for construction. In addition, it requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly the following: (1) a report of its 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.

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 that contains specific information that is set out in subsection (c) of the Rule and provides that the Public Staff and any other intervenor may file its own report, evaluation, or comments regarding the utilities' reports. In addition, Rule R8-62(p) requires that certain additional information be included in the reports about the construction of transmission lines.

In its July 13, 1999 Order Adopting Least Cost Integrated Resource Plans and Clarifying Future Filing Requirements in Docket No. E-100, Sub 82, the Commission imposed additional requirements for the annual reports. Specifically, the utilities were directed to include a full response to each item of information required by the Rules; appropriate explanations for each item where the information requested is not available; and appropriate explanations referencing the location of information in the filings where such information does not follow the same general order of presentation as contained in the Commission Rules. The Commission further ordered the utilities to adhere to the requirement that each ten-year forecast and plan consist of the ten years next succeeding the annual September 1 filing date. Also, in that order and subsequent proceedings, the Commission required the utilities to file in their annual reports a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of projected reserve margins and a discussion of the adequacy of the respective utility's transmission system.

In its March 28, 2002 Order Approving Integrated Resource Plans in Docket No. E-100, Sub 93, the Commission directed that, in order to develop a more complete list of total generation resources located in the State, the utilities provide a separate list of all non-utility electric facilities in the North Carolina portion of their control areas, including customer-owned and stand-by generating facilities, to the extent possible.

Finally, in its February 20, 2003 Order Adopting Integrated Resource Plans in Docket No. E-100, Sub 97, the Commission ordered that all future Integrated Resource Plan (IRP) filings by the utilities should include information on levelized busbar costs for various generation technologies.

On or about September 1, 2004, the current IRP filings were made under the Commission's Rules by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (Progress); Duke Power, a division of Duke Energy Corporation (Duke); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (NC Power); North Carolina Electric Membership Corporation (NCEMC); and Western Carolina Energy, LLC (WCE).

WCE was formed in 2003 by Blue Ridge EMC, EnergyUnited, Piedmont EMC and Rutherford EMC, who had previously been all-requirements members of NCEMC. The majority of their remaining NCEMC power purchase contracts expire within the next five years. The WCE alliance was formed so that the four cooperatives could collectively secure their incremental power supply needs from a supplier other than NCEMC.

On November 30, 2004, the Public Staff filed its comments on the IRPs submitted by the utilities, including a discussion of reserve margin adequacy. No party formally petitioned to intervene in this proceeding.

A public hearing was held on February 7, 2005, in Raleigh, for the purpose of receiving non-expert public witness testimony. The Attorney General's office made an appearance at the hearing pursuant to G.S. 62-20. No public witnesses appeared to testify.

COMPLIANCE WITH FILING REQUIREMENTS

The Public Staff comments contained a review of the utilities' responses to information requirements contained in Rules R8-60(c) and R8-62(p). According to the Public Staff, the utilities responded to all subsections and generally complied with the Commission's previous orders concerning IRP. Further, the Public Staff did not identify any issue that required an evidentiary hearing and was satisfied with the annual reports.

PEAK AND ENERGY FORECASTS

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

The following table summarizes the 2005-2014 growth rates for the utilities' system peak loads and annual energy sales.

2005 - 2014 Annual Growth Rates

	Summer Peak[1]	Average Annual MW Growth	Winter Peak	Energy Sales
Progress	1.4%	177	1.4%	1.8%
Duke	1.4%	260	0.9%	1.2%
NC Power	1.6%	286	1.4%	1.6%
NCEMC	2.2%	60	2.2%	2.2%
WCE	3.0%	37	2.9%	3.2%

All of the major utilities have reduced their predicted annual average peak growth rates. These reductions in the peak loads are due, in part, to a continuing decline in industrial and native wholesale loads.

DEMAND-SIDE MANAGEMENT (DSM) OPTIONS

The Public Staff has continued to point out that the utilities' emphasis on DSM programs has waned since the mid-1990's. None of the utilities' filings listed any new programs under consideration.

G.S. 62-2(3a) provides that it is the policy of this State "[t]o 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. . .[and] [t]o 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. . ."

According to the Public Staff, each utility complied with Rule R8-60(c)(9) by providing a list of current DSM programs.

RESERVE MARGINS

In the 1970's and 1980's it was considered appropriate to use a 20% planning reserve margin target due to the size of the baseload powerplants (coal and nuclear) relative to the size of utility systems they served, and the high rate and duration of forced and scheduled outages during that period, particularly for nuclear plants. Today, however, those same nuclear plants are operating with very low forced outage rates and short refueling outages, and the large baseload generating units are responsible for meeting a significantly smaller portion of system peak demand.

Reserve margins shown in the current IRP filings are comparable to those submitted in the last proceeding. For the planning period 2005 to 2014, the range of summer reserve margins reported by the utilities remains below 20%. For this period, the planned reserves are: Progress, 13% to 18%; Duke, 17%; and NC Power, 12.5%. NCEMC and WCE assume that all capacity purchases will be 100% firm with reserves provided by the supplying entity. Future purchases will include reserves or NCEMC and WCE will acquire them independently.

[1] All of the utilities, except WCE, consider their summer peak to be the annual system peak. WCE uses a winter peak.

Because of the decline in actual summer operating reserve margins and planned reserve margins reported to the Commission in Docket No. E-100, Sub 82, the Public Staff filed Comments on December 3, 1998, contending that the issue of declining reserve margins required further explanation by the utilities. On July 19, 1999, the Commission ordered the utilities to file a detailed justification for the adequacy and appropriateness of the level of the projected reserve margin in their annual filings. The utilities responded to this continuing requirement in their 2004 filings.

According to the Public Staff, Progress, Duke, and NC Power appear to meet their projected reserve margin targets for the planning period. The Public Staff believes that reserves should be adequate and recommends that Progress, Duke, and NC Power maintain their reserve margins as filed.

TRANSMISSION ADEQUACY

The March 28, 2002 Commission Order Approving Integrated Resource Plans required that future IRP filings by all utilities shall include a discussion of their respective utility's transmission system (161 kV and above). The Commission also required that the utilities shall meet with the Public Staff within 30 days of the filing date of their annual reports to discuss detailed information concerning their transmission system.

The Public Staff indicated that the companies included in their annual report filings discussions of the adequacy of their transmission systems and copies of their most recently completed FERC Form 715. The companies also met with the Public Staff to discuss detailed information concerning their transmission line inter-tie capabilities, transmission line loading constraints, and planned new construction and upgrades for the planning period under consideration.

NON-UTILITY GENERATION FACILITIES

In its recent Orders Approving Integrated Resource Plans, the Commission has required that the utilities provide a separate list of all non-utility electric facilities in the North Carolina portion of their control areas, including customer-owned and stand-by generating facilities, to the extent possible.

All utilities continued to comply with this requirement in their 2004 reports.

BUSBAR INFORMATION

In its March 24, 2004 Order, the Commission directed Progress, Duke and NC Power to include information on levelized busbar costs for various generation technologies in their September 1, 2004 filings. In compliance with the Order, each utility included this information in its report.

CONCLUSIONS

Peak and Energy Forecasts

The Commission finds that the utilities continue to use accepted econometric and end-use analytical models to forecast their peak and energy needs.

Demand-Side Management (DSM) Options

The Commission reaffirms the value of cost-effective DSM programs, and concludes that it should continue to encourage the appropriate application of DSM options in the total resource mix of each utility.

Reserve Margins

The Commission continues to recognize that the electric power industry remains in the midst of an economic and regulatory transition and that the resulting changes and uncertainty have led to the rethinking of certain long-accepted industry standards. As a result of these changes, as well as the information contained in the present record, the Commission does not believe that it is appropriate to mandate a particular reserve margin for any jurisdictional electric utility at this time. The Commission concludes that it remains more prudent to continue to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission believes that existing generation resources are adequate in light of current conditions. The Commission does, however, want the record to again clearly indicate that providing adequate service continues to remain a fundamental obligation imposed upon all jurisdictional electric utilities, that it will be actively monitoring the adequacy of existing electric utility reserve margins, and that it will take appropriate action in the event that any reliability problems develop.

The Commission concludes that future IRP filings by all utilities should continue to include a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of the respective utility's projected reserve margins.

Transmission Adequacy

The Commission notes the ongoing discussions between the companies and Public Staff relating to transmission adequacy. Each utility again provided a copy of their most recently completed FERC Form 715 in their annual report filings, including attachments and exhibits, and met with the Public Staff to discuss various transmission related issues. The Commission supports this ongoing dialogue between the companies and the Public Staff.

The Commission further concludes that future IRP filings by all utilities should continue to include a discussion of the adequacy of the respective utility's transmission system (161 kV and above), as well as a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

Non-Utility Generation Facilities

The Commission finds that all utilities included a separate list of non-utility electric facilities in their 2004 annual reports, and that each utility should continue to provide this information in future reports.

Busbar Information

The reports of Progress, Duke, and NC Power each included sections addressing levelized busbar costs. The Commission continues to find value in this type of information in understanding the screening process used by the utilities, and requests that the utilities include this information in future reports.

Approval of IRPs

As stated in previous IRP dockets, the Commission is of the opinion that the IRP review is intended to ensure that each utility is generally including all of 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. Consistent with this view, it should be emphasized that inclusion of a DSM program, a proposed new generating station, a proposed new transmission line, or a purchased power contract in a utility's IRP filing does not constitute approval of such individual elements even if the IRP itself is approved.

The Commission concludes that the current IRPs should be approved. No party has argued that the IRP filed by any utility should be rejected.

IT IS, THEREFORE, ORDERED as follows:

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

2. That the IRPs filed by Progress, Duke, NC Power, 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. This information should include facility name, primary fuel type, capacity and location, and should indicate which facilities are included as part of their total supply resources; and

7. That future IRP filings by Progress, Duke, and NC Power shall continue to include information on levelized busbar costs for various conventional, demonstrated, and emerging generation technologies. 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. In addition, a redacted, non-confidential version of the information in question shall also be included in the annual report filings.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of February, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

mr022105.01

DOCKET NO. P-100, SUB 72b

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of .		
Implementation of Session Law 2003-91,	)	ORDER CLARIFYING RULING
Senate Bill 814 Titled "An Act to Clarify the	)	ON PROMOTIONS AND
Law Regarding Competitive and Deregulated	)	DENYING MOTIONS FOR
Offerings of Telecommunications Services"	)	RECONSIDERATION AND STAY

BY THE COMMISSION: On December 22, 2004, the Commission issued *Order Ruling on Motion Regarding Promotions.* On February 18, 2005, BellSouth Telecommunications, Inc. ("BellSouth") filed a Motion for Reconsideration or, in the Alternative, for Clarification, and for Stay. Also on February 18, 2005, Image Access, Inc. d/b/a New Phone ("New Phone") filed a Petition to Intervene and Comment Out of Time. The Commission granted New Phone's Petition to Intervene on March 3, 2005, and accepted New Phone's Comments for the record, but did not otherwise address them. This Order addresses both New Phone's comments and BellSouth's motion.

<u>**New Phone's Comments**</u>

A. The Commission's forecast and 47 C.F.R. 51.613(a)(2)

In its comments, New Phone complains that the Commission considered a specific promotion, which BellSouth offered in excess of 90 days, and forecasted that the Commission would be inclined to find that a restriction on the resale of the promotion was reasonable and nondiscriminatory. New Phone notes that the Commission's forecast was *dictum,* based in part on the Commission's perception that Competing Local Providers ("CLPs") did not object to BellSouth's refusal to offer the promotion for resale since no CLP filed comments or objections. New Phone explains that it and other CLPs were not indifferent on this issue, but failed to file comments or objections because the Commission's July 7, 2004 *Order* seeking comments did not indicate that specific BellSouth promotions of more than 90 days' duration would be considered or approved. According to New Phone, without regard to whether a CLP files an objection, Federal Communications Commission ("FCC") Rule 47 C.F.R. 51.613(a)(2) establishes that it is unreasonable and discriminatory for an ILEC to refuse to resell telecommunications services at the promotional rate minus the percentage wholesale discount when the promotional rate is offered to retail customers for more than 90 days.

DISCUSSION

First, the Commission does not agree that its July 7, 2004 *Order* failed to provide CLPs with notice that BellSouth's 1FR + 2 Cash Back promotion could be under consideration. The Public Staff's motion for a ruling on promotions made express mention of the 1FR + 2 Cash Back promotion, the dispute with BellSouth regarding the availability of the promotion for resale, and the start and end dates for the nine-month promotion. In addition, the Public Staff's motion was an attachment to the Commission's *Order,* and the Public Staff again specifically identified and discussed the 1FR + 2 Cash Back promotion in the comments it filed on August 6, 2004 pursuant to the Commission's *Order.* Thus, the Commission believes that New

Phone and other CLPs had adequate notice that the Commission could address the 1FR + 2 Cash Back promotion in examining and clarifying BellSouth's resale obligations. Nevertheless, the Commission granted New Phone's Petition to Intervene and accepted New Phone's comments for the record. Because New Phone's comments were not filed in time to be considered prior to issuance of the December 22nd *Order*, the Commission will consider them now and will treat them as a motion for reconsideration or, in the alternative, for clarification of the Commission's *Order Ruling on Motion Regarding Promotions.*

Second, the Commission generally agrees with New Phone's interpretation of 47 C.F.R. 51.613(a)(2): if a promotion involves rates that will be in effect for more than 90 days, an ILEC shall apply the wholesale discount to the special promotional rate for retail service rather than to the ordinary rate. The FCC has stated in express terms that short-term promotional prices do not constitute retail rates that are subject to the wholesale percentage discount and has defined short-term promotions to be those offered for no more than 90 days. The FCC reasoned that a promotion offered for 90 days or less has procompetitive effects that outweigh the anticompetitive effects of restricting the resale of such a promotion.[1] The clear implication of the FCC's rule and related opinions is a presumption that it is unreasonable and discriminatory for an ILEC not to resell telecommunications services at the promotional rate minus the percentage wholesale discount when the promotional rate is offered to retail customers for more than 90 days.

However, in its December 22nd *Order*, the Commission recognized that the FCC clearly intended that an ILEC may rebut this presumption as to promotions offered in excess of 90 days by proving that a restriction on resale of such promotions is reasonable and nondiscriminatory. "With respect to any restrictions on resale not permitted under paragraph (a) [*e.g.*, a restriction on the resale of a long-term promotion that is offered for more than 90 days], an incumbent LEC may impose a restriction only if it proves to the state commission that the restriction is reasonable and nondiscriminatory."[2] That is to say, not all promotions offered for more than 90 days necessarily have anticompetitive effects that outweigh procompetitive effects. It may not always be unreasonable and discriminatory for an ILEC not to apply the wholesale discount to the 90-day-plus special promotional rate.

By its *dicta,* the Commission did not intend to suggest a change of law or to disregard existing FCC rules and orders. Instead, the Commission's discussion of the dispute implicated by BellSouth's 1FR + 2 Cash Back promotion recognized that FCC rules do permit an ILEC to restrict resale of a promotion offered at retail for more than 90 days, upon *proving* that the restriction is reasonable and nondiscriminatory. The Commission's discussion of factors an ILEC may present to establish that a restriction is reasonable and nondiscriminatory was not intended to be exhaustive nor meant to suggest that the presence of any one or all of the factors would be sufficient to prove that a given restriction is permissible under the FCC's rules. Rather, the Commission's opinion stressed that each 90-day-plus promotion, including the 1FR + 2 Cash Back promotion, would have to be examined on a promotion-by-promotion basis, and that, in the absence of an objection by a reseller, the stated factors could be considered and could have some

[1] *In the Matter of Implementation of the Local Competition Provisions in the Telecommunications Act of 1996*, (CC Docket 96-98); First Report and Order, FCC No. 96-325, 11 FCC Rcd 15499 (rel. August 8, 1996) ("Local Competition Order"), ¶¶ 949-50.

[2] 47 C.F.R. 51.613(b).

persuasive value to the Commission in determining whether a particular restriction on resale is reasonable and nondiscriminatory.

CONCLUSIONS

To clarify, the Commission's December 22, 2004 *Order* should not be read as a change of law or policy. If the Commission is called upon to determine whether a promotion offered for more than 90 days must be offered to resellers at the promotional rate minus the wholesale discount, the Commission will follow the law as stated in 47 U.S. C. 251(c)(4) and 47 C. F. R. 51.613 (a)(2) and (b). In order to withhold the benefit of a long-term (90-day-plus) promotional rate from resellers, an ILEC is first required to "[prove] to the [Commission] that the restriction is reasonable and nondiscriminatory." The Commission's discussion of the 1FR + 2 Cash Back promotion was intended only to offer a modicum of guidance as to some of the kinds of factors the Commission might find probative, in the absence of objection, should an ILEC seek to prove that a restriction on resale is reasonable and nondiscriminatory. The burden of proving any restriction reasonable and nondiscriminatory remains with the ILEC. The factors acknowledged by the Commission were not intended to be exhaustive or necessarily sufficient to meet the ILEC's burden of proof. The Commission will consider all arguments and admissible evidence presented and decide on a promotion-by-promotion basis (with regard to promotions offered in excess of 90 days) whether an ILEC has proved that a restriction on resale is permissible pursuant to 47 C.F.R. 51.613(b). The Commission cannot authorize a restriction on resale of a long-term promotion in the absence of such proof.

B. The Commission's forecast and the parties' interconnection agreement

New Phone states in its comments that it is concerned that BellSouth may rely on the Commission's forecast with respect to the 1FR + 2 Cash Back promotion to avoid its obligation to resell promotions as provided by the terms of BellSouth's interconnection agreement with New Phone ("Agreement"). According to New Phone, the Agreement provides that BellSouth must resell all telecommunications services at the wholesale discount rate subject to a list of restrictions set forth in the Agreement. New Phone states that the Agreement provides that all promotions must be available for resale at the wholesale discount rate except those promotions, as identified in the list of restrictions, which are offered for less than 90 days. New Phone further notes that the Agreement contains Parity provisions that may be violated if BellSouth fails to resell promotions in accordance with the terms of the Agreement.

DISCUSSION AND CONCLUSION

The Commission's December 22, 2004 *Order* does not relieve any party of obligations it might have under an existing interconnection agreement. The Commission does not, based on the present record, express any opinion about the extent of any party's obligation under New Phone's interconnection agreement with BellSouth. Moreover, the Commission has no evidence before it suggesting that BellSouth has any intent to avoid the obligations established by its interconnection agreement with New Phone. Accordingly, the Commission clarifies that its December 22, 2004 *Order* relieves no party of any resale obligations it might have under an existing interconnection agreement.

BellSouth's Motion

A. Resale Obligations and One-time Gift Promotions

In its motion for reconsideration or clarification, BellSouth argues that the Commission created a novel resale obligation for one-time incentive gifts that ILECs provide to their customers. According to BellSouth, the Commission's *Order* requires one-time upfront gifts "that are funded in whole or in part by the ILEC's regulated service operations" and offered as incentives to customers subscribing to retail services to be "made available to resellers, unless the ILEC proves to the Commission that not making [such gifts] available for resale is reasonable and nondiscriminatory." BellSouth suggests that the Commission's ruling on resale obligations is based on language in the *Order* stating that "anything of economic value paid, given, or offered to a customer to promote or induce purchase of a bundled service offering of both regulated and nonregulated telecommunications services is a promotional discount." BellSouth calls the result of the Commission *Order* "patently silly" and "bizarre" because, according to BellSouth, the *Order* would require BellSouth "to give a CLP . . . a toaster for each customer to whom the CLP resells [a given] service," if BellSouth offers a toaster to any customer subscribing to that same service. BellSouth re-asserts its initial argument that because one-time gifts offered as incentives are not themselves "telecommunications services," they are not subject to the resale obligations of the Telecommunications Act of 1996 ("TA 96"). BellSouth further complains that CLPs are not required to pass the benefit of the promotional rate on to their customers and that it will often be difficult, if not impossible, to determine the value of one-time incentive gifts, since ILECs generally do not pay face value for such gifts.

DISCUSSION

First, the Commission notes that BellSouth appears to cite language from Part A of the Commission's *Order*, which pertains to the interpretation of a state statute concerning when notice of a promotion or a bundled service offering must be filed, to complain about the Commission's holding in Part B of the *Order*, which pertains to federal resale obligations under TA 96. To clarify, the Commission's holdings with respect to resale obligations are not based on the ILEC's funding source for incentive gifts or marketing tools. The Commission's discussion of the source of funding for a promotion applies only to the interpretation of the state statute at issue in Part A of the *Order*.

Second, notwithstanding BellSouth's characterizations, the Commission's *Order* creates no new resale obligations. Section 251(c)(4) of TA 96 requires an ILEC "to offer for resale at wholesale rates any telecommunications services that the carrier provides at retail to subscribers who are not telecommunications carriers." Section 252(d)(3) provides that the wholesale rates are to be determined on the basis of rates charged to subscribers. The Commission's *Order* merely recognizes what the FCC found in its 1996 Local Competition Order, *i.e.*, that long-term promotional offerings offered to customers in the marketplace for a period of time exceeding 90 days have the effect of changing the actual retail rate to which a wholesale requirement or discount must be applied. The FCC stated that there is to be no general exemption of promotional offerings from the wholesale requirement. However, in the same order, the FCC held that promotional offerings are exempt from the wholesale requirement if they are offered for 90 days or less because such short-term promotional offerings do not constitute the actual retail rate. The wholesale requirement, therefore, would not apply to such short-term promotions because they have been determined by the FCC not to change the actual retail rate. This bright line test was the FCC's compromise between allowing and not allowing ILECs to offer promotions that could undercut reseller pricing, so that short-term promotions, deemed procompetitive and beneficial to customers, would not have to be unnecessarily restricted.

One-time incentive gifts, including gift cards, check coupons and other merchandise, which are offered to induce customers to subscribe to telecommunications services, are promotional offerings. Therefore, if such gifts or incentives are offered for more than 90 days, as discussed in greater detail in the *Order*, they have the effect of lowering the actual, "real" retail rate. The retail rate, and thus the wholesale rate charged to resellers, must be determined on the basis of the "real" rate charged to subscribers. The Commission's *Order* does not prevent or in any way frown upon the use of such incentives as gift cards and other one-time upfront gifts. However, if the incentives, *i.e.*, promotions, are offered for more than 90 days, on the 91st day, resellers are entitled to have the benefit of the promotion reflected in the wholesale rate, meaning that the wholesale discount must be applied to the promotional rate—not to some other theoretical listed rate which has been undercut by a long-term promotional rate that is generally available to subscribers in the telecommunications marketplace. If an ILEC does not want to offer resellers a wholesale rate based on a retail rate adjusted to reflect the effect of a promotion on the actual retail price, then the ILEC must not offer the promotion for more than 90 days.

Third, the Commission did not create a novel approach or new law when it held that "in order for a gift card type promotion not to require an adjustment to the resale wholesale rate . . . such a promotion must be limited to 90 days, unless the ILEC proves to the Commission that not applying the resellers' wholesale discount to the promotional offering [rate] is a reasonable and nondiscriminatory restriction on the ILEC's resale obligation." As discussed above with respect to New Phone's comments, FCC Rule 51.613(b), read in tandem with Rule 51.613(a)(2), has long provided for the possibility that an ILEC could avoid applying the wholesale discount to the special promotional rate if the ILEC is able to prove that withholding the availability of the promotional rate from the reseller is reasonable and nondiscriminatory.

Fourth, the Commission is not persuaded by BellSouth's argument that one-time incentive gifts such as gift cards and toasters are not "telecommunications services" required to be resold pursuant to TA 96. The *Order* does not require that non-telecommunications services, such as gift cards, check coupons, or merchandise, be resold. Such items do, however, have economic value. In recognition of this fact, the *Order* requires that telecommunications services subject to the resale obligation of Section 251(c)(4) be resold at rates that give resellers the benefit of the change in rate brought about by offering one-time incentives for more than 90 days. The *Order* does not require ILECs to provide CLPs with toasters, phones, knife sets, hotel accommodations, gift cards, *etc.* that they might provide to their customers as an incentive to purchase services. The *Order* does require that the price lowering impact of any such 90-day-plus promotions on the real tariff or retail list price be determined and that the benefit of such a reduction be passed on to resellers by applying the wholesale discount to the lower actual retail price.

Fifth, BellSouth complains that the Commission did not determine the value of various gift incentives or provide guidance on making such determinations, given that the ILECs' costs to acquire incentive gifts are likely not the same as the face value or actual value of the gifts to the customers. The Commission did not address determining the value of the benefit of an incentive gift promotion nor did it attempt to set strict guidelines for determining the actual rate for a service based on the value of any particular type of incentive gift. The Commission intentionally left this matter open so that the parties would be free to negotiate and arrive at a mutually agreed upon real retail rate. Irresolvable disputes in this area may be brought to the Commission for decision. However, to the extent that it is impossible either to reach a fair accommodation or agreed upon rate based on the promotional offer, or to provide the benefit of the promotional rate to resellers because it is too difficult to calculate such a rate, then, in the absence of contrary proof, such 90-day-plus promotions would be unreasonable and discriminatory and could not be approved.[1]

Finally, BellSouth complains that CLPs will not be required to pass on the benefit of the promotional rate to their customers. According to BellSouth, a CLP would have every incentive to keep the benefit for itself as a windfall over and above the wholesale discount it already receives. The resale obligation of TA 96 permits a CLP to use the wholesale discount in a way that is beneficial to it without requiring the benefit to be passed directly to end users, so it is possible that a reseller could choose not to pass the promotional rate on to its customers. However, the Commission believes such an outcome is unlikely because the reseller's success is based on being able to sell services at prices that are competitive with the ILEC's prices in the marketplace. If the ILEC offers a long-term promotion and that promotional rate continues to be generally available in the market after the 90th day of a promotion, the reseller will need to offer its services at a competitive price and will likely want to maintain the price differential it usually maintains between the ILEC's retail rates and the rates it charges customers. Moreover, BellSouth's argument seems to contemplate that the gift would be provided directly to the CLP, *e.g.*, if a $100 coupon was offered to BellSouth's customers, BellSouth would have to provide resellers with a $100 cash payment for each of its customers. However, as discussed above, the *benefit* (not the gift itself) would be delivered to the reseller through the wholesale price charged to the reseller, thus, further reducing the likelihood of undue windfall as described by BellSouth.

CONCLUSION

The Commission's *Order* regarding resale obligations applicable to one-time gift promotions, pursuant to TA 96, is clarified in accordance with the foregoing discussion.

B. Resale obligations with respect to mixed bundles

BellSouth complains that, with respect to mixed bundles of telecommunications services and non-telecommunications services, the Commission's *Order* requires ILECs to make the regulated services in the bundle available for resale at a "super discount." According to BellSouth, this super discount results because the *Order* requires the wholesale discount to be applied to the difference between the tariff rate for the telecommunications services in the mixed bundle and the entire price of the bundle, whenever the bundle is offered for a total price that is less than or equal to the stand-alone tariff price for the regulated telecommunications service. Thus, BellSouth believes the *Order* requires ILECs to resell piece-meal portions of mixed bundles at a "super discount." BellSouth argues that it should not be made to break apart such bundles. An ILEC has no obligation to resell either non-telecommunications services that it

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[1] Prior approval is not required under N.C.G.S. 62-133.5(f), but starting on the 91st day of a promotional offering, "an incumbent LEC may impose a restriction [on the resale obligation] only if it [has proved] to the state commission that the restriction is reasonable and nondiscriminatory." 47 C.F.R. 51.613(b).

provides, or any services (telecommunications or non-telecommunications services) that are provided by entities other than the ILEC.

DISCUSSION

At the outset, the Commission notes that its *Order* addressed the Public Staff's specific questions, which focused on resale obligations with respect to *regulated* telecommunications services that were part of a gift card promotion or that were part of a bundle of regulated and nonregulated services. Therefore, the *Order* generally discussed resale obligations regarding component services in a mixed bundle in terms of regulated and nonregulated services. However, pursuant to Section 251(c)(4), an ILEC is required "to offer for resale at wholesale rates any telecommunications service that [the ILEC] provides at retail to subscribers who are not telecommunications carriers." It follows from Section 251(c)(4) that an ILEC must resell all telecommunications services, whether regulated or nonregulated, at the true retail price minus the wholesale discount. Thus, an ILEC must offer the reseller any regulated telecommunications services it provides at retail (the tariff list price) for the wholesale rate, and it must also offer the reseller any nonregulated telecommunications services it provides at retail (the retail list price) for the wholesale rate. Accordingly, hereinafter, the Commission will discuss the resale obligation in terms of telecommunications services and non-telecommunications services, not in terms of regulated and nonregulated services.

BellSouth correctly states that an ILEC is not required to resell either non-telecommunications services that it provides or any services that are provided by an entity other than the ILEC. The Commission's *Order* imposed no resale obligation in conflict with this stated principle. The *Order* does not require an ILEC to resell a mixed bundle that contains inside wire maintenance (a non-telecommunications service) nor a mixed bundle that contains long distance service (a telecommunications service) supplied by a non-ILEC such as BellSouth Long Distance, Inc. However, the Commission's *Order* does require that an ILEC make any telecommunications services provided by it and offered as a component of a mixed bundle available for resale on a stand-alone basis for the wholesale rate, which must be determined by applying the wholesale discount rate to the actual, retail, marketplace rate. Accordingly, with respect to mixed bundles of telecommunications services and non-telecommunications services or telecommunications services and services offered by non-ILECs, determining the actual retail rate of any ILEC-provided telecommunications services that are in the bundle is crucial to calculating the wholesale rate a reseller must pay to resell such telecommunications services. As discussed in the *Order*, short-term promotional rates offered for 90 days or less do not constitute retail rates for telecommunications services, but long-term promotional rates offered for 91 days or more do constitute the retail rates that must be used to determine the reseller's wholesale rate.

In its discussion of a "super discount" resale obligation, BellSouth has misunderstood the Commission's *Order*, which the Commission finds should be clarified with respect to resale obligations relating to telecommunications services offered as part of a mixed bundle. When a package or bundle of a telecommunications service and a non-telecommunications service is offered in excess of 90 days for a total price that equals the price of the telecommunications service, *i.e.*, the price of the telecommunications service is not lowered but the customer receives added value for the price of the telecommunications service alone, the real retail rate in the market for the ILEC-provided telecommunications service must be determined by accounting for the value of the services in the bundle that are not telecommunications services provided by the ILEC. In this situation, the price for the telecommunications service provided by the ILEC is reduced by the value received in the form of additional non-telecommunications services and/or non-ILEC provided services. Thus, if Telecommunications Service 1 ("TS1") retails for $50 and a mixed bundle consisting of TS1, a Non-Telecommunications Service, and Satellite Television provided by a non-ILEC entity retails for $50, then TS1 is being discounted by the value of the other services in the bundle (which may appear to be provided as a free gift). If this mixed bundle is offered for 91 days or more, then the wholesale rate that the reseller must pay for TS1 is determined by applying the wholesale discount (to be determined in accordance with the discussion on Pages 6-7 above) to the promotional rate for TS1, which is determined by subtracting the value (benefit) of the giveaways (the Non-Telecommunications Service and the non-ILEC provided Satellite Television Service) from the tariff or retail list price for TS1.

When a package or bundle of a telecommunications services and a non-telecommunications service is offered in excess of 90 days for a total price that is less than the price of the telecommunications service, the real retail rate for the telecommunications service is the total price of the bundle. That is to say, when the total bundle price is less than the telecommunications service in the bundle, the ILEC has determined the value of the discount from the tariff or retail list price and has thereby determined that the actual retail rate for the telecommunications service is the price of the total mixed bundle. (There is no requirement that discounts applicable to individual components sold together in a bundle be determined or passed on to resellers.) For example, if TS1 retails for $50 and Telecommunications Service 2 ("TS2") retails for $75, while a mixed bundle consisting of TS1, TS2, a Non-Telecommunications Service, and Satellite Television is offered for $60, then TS2 is actually available in the marketplace for a real retail rate of $60. A customer whose goal is to acquire TS2 for the best price in the market can do so by paying $60 for the bundle rather than the retail list price of $75, although he must also accept additional services in order to acquire TS2 at the lower rate. Therefore, the wholesale rate that the reseller must pay for TS2 is determined by applying the wholesale discount to $60, the promotional rate for TS2. In this example, the mixed bundle sells for more than the retail price for TS1, so TS1 is not available in the marketplace for less than the tariff or retail list price of $50. The customer whose goal is to purchase TS1 for the best price in the market would not purchase the $60 mixed bundle just to acquire TS1, because he can purchase TS1 for less at the retail list price. Accordingly, an ILEC is only obligated to resell TS1 at the retail list price minus the wholesale discount.

In another example, if TS2 again retails on a stand-alone basis for $75 and a Non-Telecommunications Service retails for $10, while a mixed bundle of TS2 and the Non-Telecommunications Service is offered for more than 90 days for $25, then TS2 would be available in the market for a real retail rate of $25 even though a subscriber would have to accept the entire bundle to obtain TS2 for that price. Thus, TS2 should be offered to the reseller at the wholesale rate, which would be determined by applying the wholesale discount to the TS2 promotional rate of $25.

Looking at BellSouth's example on Page 7 of its Motion for Reconsideration, where telecommunications service A retails for $30, telecommunications service B retails for $10, and a bundle of both A and B is priced at $25 for a period in excess of 90 days, a reseller must pay $25 minus the wholesale discount for service A, since a customer could purchase service A for less than $30 by purchasing the bundle for $25. That is to say, the real retail rate for service A would be $25. For service B, the reseller must pay $10 minus the wholesale discount because the real retail rate for service B remains at $10, *i.e.*, a customer cannot acquire service B for less than $10 by purchasing the bundle. The reseller would not be entitled to purchase service A alone for $15 ($40 [A + B] minus $25 = $15) minus the wholesale discount as BellSouth apparently believed was required by the Commission's *Order*. It should be noted that if service B is changed to a non-telecommunications service or to a non-ILEC provided service, the ILEC would have no obligation to offer service B to a reseller at the wholesale rate.

Finally, to reiterate, as was noted above and in the *Order*, when the entire mixed bundle is offered for a price that is more than an end-user subscriber would pay for a telecommunications service if purchased alone at the retail list price, an ILEC is not required to resell the telecommunications services in the bundle for a price that is lower than the retail list price minus the wholesale discount. Instead, the ILEC is only required to resell such telecommunications services at the listed retail price minus the wholesale discount. For example, TS1 retails for $50, while a mixed bundle of TS1, a Non-Telecommunications Service and Satellite Television supplied by a non-ILEC is offered at $80. In this example, the mixed bundle cannot be purchased as a lower cost means of acquiring TS1. Thus, the wholesale rate for TS1 would continue to be determined by applying the wholesale discount to the tariff or retail list price for TS1, not the promotional rate that a customer might receive for TS1 if it is purchased as part of the bundle. To clarify further, the Commission's *Order* does not require an ILEC to calculate internal discount prices of components offered in a bundle and then "pick apart" the bundle to offer those internal discounts applicable to telecommunications services (discounts that are never offered to retail customers on a stand-alone basis) to resellers.

CONCLUSION

The Commission's *Order* regarding federal resale obligations applicable to mixed bundles is clarified in accordance with the foregoing discussion.

DISPOSITION OF MOTIONS

WHEREUPON, the Commission disposes of the parties' motions as follows:

1. New Phone's Motion to Reconsider IS DENIED.

2. New Phone's alternative Motion for Clarification IS GRANTED in accordance with the foregoing discussion and conclusions stated hereinabove in the section captioned "New Phone's Comments."

3. BellSouth's Motion to Reconsider and its Motion for Stay ARE DENIED.

4. BellSouth's alternative Motion for Clarification IS GRANTED in accordance with the foregoing discussion and conclusions stated hereinabove in the section captioned "BellSouth's Motion."

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of June, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

tb052305.01

DOCKET NO. P-100, SUB 99

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of BellSouth Telecommunications, Inc. in	)	ORDER GRANTING FORCE
Relief of Quality of Service Objectives for Local	)	MAJEURE WAIVER
Exchange Telephone Companies	)	

BEFORE: Chairman Jo Anne Sanford and Commissioners J. Richard Conder, Robert V. Owens, Jr., Sam J. Ervin, IV, Lorinzo L. Joyner, James Y. Kerr, II, and Michael S. Wilkins

BY THE COMMISSION: On October 20, 2004, BellSouth Telecommunications, Inc. (BellSouth), filed a Petition with the Commission requesting a waiver of six network-related Service Quality Objectives for the month of September 2004, as a result of a *force majeure* event. The Quality of Service Objectives for which a waiver is requested are: (1) initial trouble reports, (2) repeat reports, (3) out-of-service troubles cleared within 24-hours, (4) regular service orders completed within 5 working days, (5) new service installation appointments not met for Company reasons, and (6) new service held orders not completed within 30 days.

Pursuant to the Commission's Order of June 4, 2004, Order Amending Commission Rule R9-8 Effective July 1, 2004, BellSouth must demonstrate that it meets the four criteria as set out in the Order, as well as filing adjusted and unadjusted data on the subject objectives to support a waiver request of *force majeure.*

BELLSOUTH'S INITIAL COMMENTS

BellSouth commented on the four criteria as follows:

(1) that the force majeure event was sufficiently serious and unusual to warrant adjustment of the monthly service quality statistics, including a detailed description of the adverse consequences of the event on the ratepayers' service and the Company's facilities.

BellSouth stated that the tropical storms of Ivan, Frances, and Jeanne caused severe flooding, damaging outside plant facilities and forcing the evacuation of work centers in Clyde and Newland, North Carolina. BellSouth further stated that 45 vehicles were damaged by extreme flooding, with 27 of those considered a total loss.

(2) that to the extent reasonably foreseeable, the company prudently planned and prepared in advance for such emergencies.

BellSouth commented that it had implemented its pre-storm plan which included having technicians standing by to restore service as well as having generators in a safe staging area for dispatch. BellSouth asserted that severe flooding prevented technicians from being able to access certain areas to repair or even assess the damage.

(3) that despite these plans and preparations, and the best efforts of the company personnel before, during, and after the event, failures to satisfy the service objectives could not have been avoided.

According to BellSouth, damage to outside plant facilities, coupled with the damage to roadways and bridges, contributed to conditions that made BellSouth's failure to satisfy service objectives unavoidable. Assessment of the outside plant damage revealed that replacement was needed of 381 poles, 20 cross boxes, and 11 Digital Loop Carrier sites. Many roads were impassable, due to damage from wastewater discharges, floating fuel tanks, and other contaminants, which forced the Department of Transportation to use Public Safety officials to block flooded and damaged roadways.

(4) that the extent and nature of the adjustment requested are appropriate for the circumstances.

BellSouth requested that the six network Quality of Service Objectives enumerated for 27 exchanges as identified in its Petition be expunged. BellSouth commented that Governor Easley and President Bush declared the mountain counties, and portions of central North Carolina, a State of Disaster and Disaster Area, respectively.

BellSouth requested that the six network service Quality of Service Objectives for the 27 exchanges be excluded from BellSouth's September data, as submitted to the Commission.

COMMENTS OF THE PUBLIC STAFF

The Public Staff stated that after examining the Petition it believes that, with one exception, the details provided by BellSouth are persuasive and sufficient to justify the waiver request. Furthermore, the Public Staff believes that additional information is necessary to demonstrate that BellSouth prudently planned and prepared in advance for these three storms.

As further commented upon by the Public Staff, "BellSouth should be expected to provide additional details on the personnel and equipment assets it deployed in staging areas for post-storm recovery, and to identify with some specificity the locations where these assets were deployed. Further, the Public Staff recommends that the Commission ask BellSouth to provide a copy of the pre-storm plan referred to in the Petition and to identify any portions of this plan that were not actually implemented." The Public Staff asserted that additional information concerning the pre-storm planning would be beneficial to the Commission to gauge prudent pre-post storm planning and recovery by a utility.

Furthermore, the Public Staff commented that it "believes that any company seeking a waiver will make a good faith effort to determine which locations have been impacted by a *force majeure* event, quantify the impacts of the event on its monthly performance statistics, and expunge data reflecting performance failures that appear to have been caused by the event." As stated by the Public Staff, BellSouth's proposal would expunge data for network service objectives that reflect both inadequate performance and adequate performance. Therefore, the Public Staff stated that it is seeking clarification from the Commission on the correct procedure to be followed in expunging data in a *force majeure* wavier.

REPLY COMMENTS OF BELLSOUTH

BellSouth commented that the Public Staff stated that the only purported deficiency it could find in Bellsouth's petition was supposedly insufficient detail related to BellSouth's planning efforts in advance of the three tropical storms, and with post-storm recovery, and to identify with some "specificity the locations where assets were deployed." BellSouth stated that it "respectfully suggests that the accumulation of such information is a misuse of company resources," because network personnel should be focused on installing and repairing service rather than developing additional reports. BellSouth further recapped the severity of the storm damage to illuminate that this weather event was completely unprecedented.

In response to the Public Staff's comment concerning pre-storm planning, BellSouth filed as an exhibit to its reply comments a copy of BellSouth's Emergency Preparedness and Restoration Guidelines for use in managing a major emergency. Furthermore, BellSouth stated that it "implemented all portions of the plan applicable to the emergency in question."

BellSouth commented that the "Public Staff advocates excluding results for each individual service measure only in those exchanges where misses occurred." BellSouth stated that the Public Staff has data available to it through the adjusted and unadjusted data to make the recommended calculations.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

After careful consideration, the Commission finds good cause, based on the specific facts of this case, to allow BellSouth to expunge the data in question for all six service objectives in the 27 named exchanges because the details provided by BellSouth in support of its request are persuasive and sufficient to justify a waiver. The severity and subsequent impact of three tropical storms to central and western North Carolina in September 2004, was indeed atypical. The Commission further accepts, as BellSouth stated, that severe flooding prevented technicians from being able to access certain areas to repair or even assess the damage. It certainly appears that the staging of equipment for post-storm dispatch and subsequent deployment was significantly impacted by damaged and flooded roadways and bridges. For these reasons, allowing BellSouth to expunge the data in question is appropriate. As a result, the Commission finds good cause to grant BellSouth's *force majeure* request.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of January, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bb013105.01
Commissioner Lorinzo L. Joyner concurs.

DOCKET NO. P-100, SUB 99

COMMISSIONER LORINZO L. JOYNER, CONCURRING: I concur in the result reached by the Majority but for different reasons. In my view, the better course of action would be for the Commission, based on the specific facts of this case, to waive a strict interpretation of the four criteria for judging a *force majeure* request and to grant a blanket exception to BellSouth to expunge the data in question for all six service objectives in the 27 named exchanges. In my view, the details provided by BellSouth in support of its request justify an exception but not a waiver. Specifically, BellSouth has not satisfied the Commission's third criterion to justify a *force majeure* waiver in those exchanges where the Company did not in fact fail the service objectives. Nevertheless, I believe that it is reasonable to grant BellSouth a blanket exception in consideration of the totality of the circumstances faced by the Company in September 2004. This approach is entirely fair to BellSouth, yet it maintains the general applicability of the four-prong test established by the Commission to judge *force majeure* waiver requests in future cases.

\s\ Lorinzo L. Joyner
Commissioner Lorinzo L. Joyner

DOCKET NO. P-100, SUB 99

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
US LEC of North Carolina, Inc. in Relief of Quality	)	ORDER GRANTING *FORCE*
of Service Objectives for Local Exchange	)	*MAJEURE* WAIVER
Companies	)	

BY THE COMMISSION: On October 25, 2004, US LEC of North Carolina, Inc. (US LEC) filed a Petition with the Commission requesting a waiver of the Repair Service Answertime Service Quality Objective for the month of September 2004 as a result of a *force majeure* event. US LEC asked that its entire Petition consisting of a cover letter and several pages of supporting documents be accorded "confidential and trade secret" status pursuant to G.S. Section 132-12. Pursuant to Commission Rule R9-8(c), as amended by Commission Order dated June 4, 2004, US LEC must demonstrate that it meets the four criteria as set out in that Order, as well as filing adjusted and unadjusted data on the subject objective to support a waiver request of *force majeure.*

On October 29, 2004, the Commission issued its Order requesting comments from the Public Staff and reply comments from US LEC.

On November 17, 2004, the Public Staff filed its comments. The Public Staff stated that after examining the waiver request, it believes that the waiver request fails to satisfy the requirements of Commission Rule R9-8(c). Further, the Public Staff stated that if US LEC cannot provide adequate details in its reply comments, then the request should be denied. Specifically, the Public Staff cited two deficiencies in US LEC's Petition of *force majeure.* First, the Public Staff stated that adjusted and unadjusted data for September 2004 were not furnished along with the waiver request. Secondly, the Public Staff opined the waiver request failed to clearly demonstrate that the company prudently planned, that failures to satisfy the service objective could not have been reasonably avoided, and that the adjustments requested are appropriate for the circumstances.

On November 30, 2004, US LEC requested an extension of time to file reply comments until December 16, 2004, which was granted by Commission Order dated, December 7, 2004.

On December 17, 2004, US LEC filed reply comments. US LEC stated that it had worked with the Public Staff on this matter and had provided certain data to support its response. US LEC requested that the information included in its response be accorded "confidential and trade secret" status pursuant to G.S. Section 132-12.

On January 5, 2005, the Public Staff filed a letter stating that US LEC's December 17, 2004 confidential filing of further information had satisfied the Public Staff's concerns expressed in its November 17, 2004 comments. Therefore, the Public Staff stated that it did not oppose the granting of the requested *force majeure* waiver to US LEC.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

After careful consideration, the Commission finds good cause, based on the specific facts of this case, to allow US LEC to expunge the Repair Service Answertime Service Quality Objective for the month of September 2004 as a result of a *force majeure* event. The severity and subsequent impact of three tropical storms to North Carolina in September 2004, was indeed atypical. As a result, the Commission finds good cause to grant US LEC's *force majeure* waiver request.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of February, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

db022305.01

DOCKET NO. P-100, SUB 99

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Quality of Service Objectives for Local Exchange Telephone Companies	))))))	ORDER GRANTING MOTION FOR RECONSIDERATION AND ACCEPTING NEGOTIATION OF POSTING SERVICE QUALITY RESULTS BY USING A 12-MONTH AVERAGE

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

BY THE COMMISSION: On December 27, 2002, the Commission issued its *Order Amending Commission Rule R9-8 and Scheduling an Evidentiary Hearing on Specific Issues*. In its *Order*, the Commission noted that the first legal issue related to website reporting concerned the Public Staff's recommendation that the Commission post service quality reports, updated on a quarterly basis, on its website. In its *Order*, the Commission concluded that

> . . . it can require [incumbent local exchange companies] ILECs and [competing local providers] CLPs to post on their websites a pass/fail statement regarding each of the Rule R9-8 requirements, together with the amount of penalties levied against them or credits or refunds required of them with citation to that part of Rule R9-8 which gave rise to the penalty, credit, or refund. The Public Staff is requested to make a similar website posting. The Commission will provide a prominent link to this information on its own website. (Page 32)

The Commission further concluded that it

> . . sees no necessary or convincing legal impediment to requiring companies to post <u>on their own websites</u> whether or not they have been assessed penalties for quality of service violations, the nature of such violations, and the amount assessed in addition to the pass/fail information. (Page 35 with emphasis in original)

Finally, the Commission stated

> [i]t would, however, be useful for the Public Staff to provide independent posting of both the pass/fail and the penalties information on its website so that all this information can be gathered in one place. The Commission will provide a prominent link to this information on its own website. (Page 35)

Motions for reconsideration of the *December 27, 2002 Order* were filed. Further, the *December 27, 2002 Order* had scheduled an evidentiary hearing to consider an appropriate maximum answertime standard for the business office and repair service and appropriate uniform reporting procedures for Operator "O" Answertime, Directory Assistance Answertime, Business Office Answertime, and Repair Service Answertime.

On March 7, 2003, the Commission issued its *Order Continuing Hearing, Comment Cycle and Amendments' Effective Date* allowing the parties to the proceeding the opportunity to conduct negotiations on issues related to the *December 27, 2002 Order.* In the *March 7, 2003 Order*, the evidentiary hearing previously scheduled was continued, the comment cycle on the motions for reconsideration was suspended, and the effective date of amended Rule R9-8 was postponed indefinitely.

On October 30, 2003, the Public Staff, on behalf of itself and the Industry Task Force (ITF), filed its Joint Report. The parties stated in the Joint Report that they had been able to resolve most of the issues in the docket and had narrowed the remaining issues. The parties noted that 17 issues remained unresolved after the negotiation process and that the parties had negotiated all other aspects of Rule R9-8. The parties stated that they believed that the disputed issues did not require a hearing, but could be resolved by the Commission after the parties had been allowed to file comments.

On November 7, 2003, the Commission issued its *Order Requesting Initial and Reply Comments* on the October 30, 2003 Joint Report. The *Order* also requested that the parties file Joint Comments listing each issue that the parties negotiated and providing detailed support for each issue negotiated if the result was different than that ordered by the Commission in its *December 27, 2002 Order.* The Commission noted in its *November 7, 2003 Order* that it "will consider the negotiated issues and, after reviewing and considering the Joint Comments, will either accept or reject each of the negotiated issues."

Initial comments were filed on December 8, 2003 and, after an extension of time, reply comments were filed on January 14, 2004. The Joint Comments were filed on January 20, 2004.

On June 4, 2004, the Commission issued its *Order Amending Commission Rule R9-8 Effective July 1, 2004.* In its *June 4, 2004 Order*, the Commission concluded for Negotiated Issue No. 11 (website reporting), as follows[1]:

> The Commission concludes that website reporting is appropriate. The Commission upholds and affirms its decision on website reporting as outlined in the *December 27, 2002 Order.* However, the Commission finds it appropriate to hold in abeyance the specific details of the website reporting requirement and the effective date of the website reporting requirement in order to allow the parties the opportunity to negotiate on a[n] appropriate means to allow the public access to the service quality information. The parties are requested to file a report with the Commission detailing the negotiations and their specific recommendations by no later than Tuesday, August 3, 2004. The Public Staff is specifically requested to facilitate the negotiation process.

Further, the Commission stated in its *June 4, 2004 Order* that "it is entirely appropriate and reasonable to uphold its conclusions on website reporting as outlined in the

[1] Commissioner Conder and Commissioner Wilkins dissented from the majority's decision on website reporting in the *June 4, 2004 Order.*

December 27, 2002 Order (See pages 33-35 of the *December 27, 2002 Order*)." The parties were instructed in the *June 4, 2004 Order* to follow the logic and intent of the *December 27, 2002 Order* concerning website reporting.

On August 3, 2004, the Public Staff, on behalf of itself and the other parties to the docket, filed its Report on Web Posting. The Public Staff noted that it had met twice with representatives from the industry to discuss this issue.

The Public Staff noted that the parties had agreed that the service quality results should be averaged over a 12-month period and updated quarterly. The Public Staff explained in a footnote that after receipt of the results from the fourth quarter of 2004, the results for each measure for each month in 2004 would be added together and divided by 12 (unless a company has applied for or received a waiver). The Public Staff noted that after receipt of the results from the first quarter of 2005, the results would be recalculated by removing the results from the first quarter of 2004 and adding in the results from the first quarter of 2005.

The Public Staff noted that there were two alternative format proposals for website posting. The Public Staff also commented that there were two other issues which required a decision by the Commission: (1) whether companies should be allowed to post comments on the website explaining certain service quality results; and (2) whether the service quality results should be posted on the Public Staff's website or the Commission's website.

On August 12, 2004, the Commission issued its *Order Requesting Comments on August 3, 2004 Report on Web Posting*. The Commission requested the parties to file initial and reply comments on the following specific issues:

(1) Whether the Commission should require (a) the posting of service quality results averaged over a 12-month period and updated quarterly; <u>or</u> (b) the posting of monthly service quality results on a quarterly basis. (See page 32 of the Commission's *December 27, 2002 Order*)

(2) Whether the Commission should adopt the website reporting format outlined in Attachment A or Attachment B of the August 3, 2004 Report on Web Posting.

(3) Whether the Commission should allow companies to post comments on the website explaining certain service quality results.

(4) Whether the Commission should require that service quality results be posted on: (a) each individual company's website; <u>and</u> (b) on the Public Staff's <u>or</u> Commission's website. (See pages 32 and 35 of the Commission's *December 27, 2002 Order*)

(5) Whether the Commission should require companies to post on their own websites the amount of penalties levied against them with citation to the service objective which gave rise to the penalty. Further, whether the Commission or the Public Staff, as appropriate, should make a similar website posting on penalties. (See pages 32 and 35 of the Commission's *December 27 2002 Order*)

Initial comments were filed on August 30, 2004 by ALLTEL Carolina, Inc. (ALLTEL), jointly by AT&T Communications of the Southern States, LLC (AT&T), MCImetro Access Transmission Services (MCI), Time Warner, and US LEC of North Carolina, Inc. (US LEC) (the Joint Commenters), the Attorney General, BellSouth Telecommunications, Inc. (BellSouth), the Public Staff, Sprint Communications Company, L.P. (Sprint), and Verizon South, Inc. (Verizon). Reply comments were filed on September 9, 2004 by Sprint and on September 13, 2004 by BellSouth and the Public Staff.

On November 8, 2004, the Commission issued its *Order Instituting Website Posting of Service Quality Results*. In its *Order*, the Commission concluded as follows for each of the five specific issues that were outstanding:

ISSUE NO. 1: Whether the Commission should require (a) the posting of service quality results averaged over a 12-month period and updated quarterly; **or** (b) the posting of monthly service quality results on a quarterly basis. (See page 32 of the Commission's *December 27, 2002 Order*)

COMMISSION CONCLUSION: The Commission found it appropriate to require the posting of service quality results (i.e., in the pass/fail format) averaged over a three-month (quarterly) period and updated quarterly.[1]

ISSUE NO. 2: Whether the Commission should adopt the website reporting format outlined in Attachment A or Attachment B of the August 3, 2004 Report on Web Posting.

COMMISSION CONCLUSION: The Commission found it appropriate to adopt the website posting format as outlined in Attachment A (except reflecting a three-month average – See Issue No. 1), with access to company-specific links as proposed by the Public Staff (i.e., via the Public Staff Communications Division's webpage).

ISSUE NO. 3: Whether the Commission should allow companies to post comments on the website explaining certain service quality results.

COMMISSION CONCLUSION: The Commission found it inappropriate to allow companies to post comments on the website explaining certain service quality results with the exception of the notation provision in Attachment A for a force majeure waiver request.

ISSUE NO. 4: Whether the Commission should require that service quality results be posted on: (a) each individual company's website; **and** (b) on the Public Staff's **or** Commission's website. (See pages 32 and 35 of the Commission's *December 27, 2002 Order*)

COMMISSION CONCLUSION: The Commission found it appropriate to require that service quality results be posted on the Commission's website only (and not the Public Staff's or each individual company's websites) and to request the Public Staff to facilitate the postings by accepting and cataloguing each company's service quality information, verifying its completeness and accuracy as needed, using the data to generate a report in a format suitable for posting, and finally, transmitting this report to the Commission Staff.

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[1] The four quarters of a calendar year would be: First – January, February, and March; Second – April, May, and June; Third – July, August, and September; and Fourth – October, November, and December.

__ISSUE NO. 5__: Whether the Commission should require companies to post on their own websites the amount of penalties levied against them with citation to the service objective which gave rise to the penalty. Further, whether the Commission or the Public Staff, as appropriate, should make a similar website posting on penalties. (See pages 32 and 35 of the Commission's *December 27, 2002 Order*)

COMMISSION CONCLUSION: The Commission concluded that companies are not required to post on their own websites (or on the Public Staff's or Commission's websites) the amount of penalties levied against them with citation to the service objective which gave rise to the penalty.

The Commission further concluded that website posting of service quality results would begin as soon as possible after the service quality reports reflecting results for January, February, and March 2005 were filed with the Commission. Therefore, the Commission found that the first posting on the Commission's website would include a three-month average of the results for January, February, and March 2005.

On December 7, 2004, BellSouth, on behalf of itself and Verizon, Carolina Telephone and Telegraph Company (Carolina), Central Telephone Company (Central), Sprint, and the Alliance of North Carolina Independent Telephone Companies[1] (collectively the Companies) filed a Motion for Reconsideration requesting the Commission to reconsider its conclusion concerning Issue No. 1 in the *November 8, 2004 Order.*

On December 14, 2004, the Commission issued an Order requesting initial and reply comments on the Motion for Reconsideration.

Initial comments were filed on January 7, 2005 by the Attorney General and reply comments were filed on January 21, 2005 by the Companies.

MOTION FOR RECONSIDERATION

The Companies requested that the Commission reconsider and reverse its conclusion that telecommunications carriers must post service quality results averaged over three months and updated quarterly. The Companies noted that in the Commission's discussion of the issue in the *November 8, 2004 Order*, the Commission noted, and then rejected, the agreement among all parties except the Attorney General[2] that posting of service quality results averaged over a 12-month period and updated quarterly was appropriate. The Companies asserted that it has been a long standing practice of the Commission to encourage negotiations and consensus building; absent a significant and material reason to reject the recommendations of the parties, including the Public Staff and, to some extent, the Attorney General, it is unclear as to how or why the Commission reached this decision.

[1] Includes Citizens Telephone Company, The Concord Telephone Company, Ellerbe Telephone Company, LEXCOM Telephone Company, MEBTEL Communications, North State Communications, and Randolph Telephone Company.

[2] The Companies asserted that the Attorney General recommended posting both a 12-month average and a quarterly average – a position hardly contrary to that taken by the industry group.

The Companies noted that the Commission authorized the creation of an Industry Task Force to review service quality reporting, and the Industry Task Force was in agreement with the Attorney General and the Public Staff that a 12-month period should be utilized for web site reporting. The Companies asserted that the Commission advanced no probative, compelling reason why the approach negotiated in good faith by the industry and the Public Staff should be overturned.

The Companies noted that the Commission advocated website posting as a means to provide useful information to consumers regarding the relative performance of different telecommunications carriers. The Companies maintained that there is no evidence that a quarterly average of service results is significantly more beneficial to customers than a 12-month rolling average which is updated quarterly. In fact, the Companies asserted, it is logical to believe that a consumer would be more interested in longer term results as opposed to a quarter-by-quarter reporting result when considering a telecommunications carrier on the basis of service quality. The Companies argued that a 12-month rolling average, updated quarterly, would meet consumer needs, smooth out anomalies in reporting results and would not be unnecessarily burdensome to any party. The Companies maintained that it has been the considerable experience of Industry Task Force members that the vast majority of customers simply do not sign up for service with the intent of remaining on the network for just one quarter; providing customers with a tool that allows them to evaluate a complete year is far more indicative of the experience they will receive over the life of their service.

The Companies argued that quarterly averaging will only serve to fuel the need for carriers to file multiple force majeure waivers to smooth out anomalous results. The Companies asserted that the fact that the Commission has also declined to allow parties to post explanatory comments along with reported results will exacerbate the need for carriers to file more, not fewer, force majeure waiver requests going forward. The Companies maintained that, in all but one of the quarters set forth in the Commission's *November 8, 2004 Order*, there is a high risk of a force majeure event that could impact telecommunications companies: January through March – ice and snow; April through June – lower risk quarter; July through September – severe thunderstorms and hurricanes; and October through December – continued risk for hurricanes and then ice and snow. The Companies asserted that filing a force majeure waiver is burdensome not only to telecommunications carriers but also to the Public Staff and the Commission. The Companies argued that simply gathering the information for a force majeure waiver poses a significant burden on a company's network forces, whose attention should be focused on repairing and provisioning service for its customers. The Companies opined that the Commission should do all it reasonably can to ensure that telecommunications companies are not encouraged to file multiple force majeure requests; averaging service results over 12 months is one step the Commission can take to achieve that goal.

The Companies maintained that not a single party to the proceeding recommended that the quarterly average be the sole reporting interval for the posting of service quality results, in large part due to ease of customer understanding of results based upon a longer period, but updated each and every quarter. The Companies asserted that the Commission, however, has issued a ruling that is in conflict with the agreement that it asked the Task Force members to reach. The Companies requested that the Commission reconsider its ruling on this issue and approve the averaging of service quality results over 12 months, updated quarterly.

INITIAL COMMENTS

The **Attorney General** stated in his initial comments that the decision on the issue at hand was a policy decision for the Commission. Therefore, the Attorney General stated, the Commission had a great deal of discretion in making the determination. The Attorney General noted that the Commission stated in its *November 8, 2004 Order* that it believed a 12-month average was inappropriate because it was simply too long a period and would not reflect recent service quality results; the Commission also noted that the force majeure clause could be utilized by any company that faced a force majeure event that impacted its service quality results in an anomalous fashion. The Attorney General asserted that the Commission's decision was well-grounded. The Attorney General further maintained that the Companies have not set forth any compelling reasons as to why the Commission abused its discretion or why its decision should be reversed.

The Attorney General stated that the Companies' argument that quarterly averaging will only serve to fuel the need for carriers to file multiple force majeure waivers to smooth out anomalous results lacks merit. The Attorney General maintained that if a company fails to comply with the service quality standards because of a force majeure event, it will likely file for a force majeure waiver whether the time period used for averaging the results is three months or 12 months. The Attorney General opined that if, on the other hand, a company fails to comply with the service quality standards for reasons that have nothing to do with a force majeure event, then it has no basis for filing a force majeure waiver. The Attorney General stated that it is difficult to see how the time period used for averaging the service quality results will provide the companies with incentives or disincentives to file legitimate force majeure waivers.

The Attorney General also noted that the Companies maintain that there is no evidence that a quarterly average is significantly more beneficial to consumers than a 12 month average. The Attorney General asserted that the benefit is self-evident and was noted in the *November 8, 2004 Order* – a quarterly average allows consumers to see more recent results. The Attorney General stated that on the other hand, with a 12 month period, if a company had a particularly good or bad quarter just before the results are posted, the high and low numbers might be smoothed out over the 12 month average and not be noticeable to the consumer.

The Attorney General maintained that if the Commission decides there is some benefit in giving consumers access to service quality results that are averaged over a 12 month period, then the Commission can always require the Companies to post the results both ways: (1) averaged over a three month period, updated quarterly; and (2) averaged over a 12 month period, updated quarterly as recommended in the Attorney General's August 30, 2003 comments. But, the Attorney General stated, in any event, the Commission's November 8, 2004 decision was sound and there is no compelling reason for the Commission to reverse its decision and go exclusively with a 12 month period as proposed by the Companies.

REPLY COMMENTS

The Companies stated in their reply comments that 12 ILECs have asked the Commission to reconsider its decision on posting quarterly service quality results and that only the Attorney General filed comments in response to the relief sought by the Companies. The Companies asserted that the Attorney General disagreed with the statement by the 12 ILECs, which was based on their considerable experience in reporting service quality results over the years, that a three-month averaging of service results would force them to file more force majeure requests than if the reporting period was 12 months in length, updated quarterly. The Companies maintained that the Attorney General's opinion that Companies would file force majeure waivers any time a force majeure event occurred, regardless of the time period used to calculate results, is incorrect. The Companies argued that a company that misses a monthly service quality measurement will know, based on its operating results over the years, that a 12-month averaging of results for that measurement will likely smooth out that result and that a force majeure waiver would not be necessary. The Companies noted that they have operated under a 12-month averaging of service quality results for decades and have extensive experience gauging the impact of an isolated, one-month's miss over a 12-month base of results. Likewise, the Companies noted, they know that missing a measurement for even one month could likely jeopardize meeting a three-month average for that measurement. The Companies asserted that it simply makes common sense that companies will err on the side of caution and file a force majeure waiver any time meeting a three-month average has been jeopardized by a one-month's miss caused by a force majeure event. The Companies opined that the Commission should give more weight to the views of the 12 operating companies on this issue than the Attorney General; they provided a credible, detailed analysis of this issue in their Motion for Reconsideration, and the Attorney General has provided no information beyond speculation.

The Companies also noted that the Attorney General disagreed with the ILECs' contention that a 12-month averaging of results would be more beneficial to consumers than a three-month average. The Companies commented that the Attorney General stated that a quarterly averaging allows consumers to see more recent results. The Companies argued that using a 12-month average allows consumers to evaluate a complete year's worth of performance by a particular company, which is far more indicative of the service the customer will likely receive over the life of the service bought from that company. The Companies questioned whether a consumer who was buying a used car would be better informed by obtaining repair records from the previous three months (i.e., the most recent results) or from repair records spanning the entire year prior to the consumer's purchase. Clearly, the Companies maintained, the consumer would be better informed by having the entire 12 months of performance history and the result is no different in the instant context.

The Companies stated that the Attorney General suggests that the Commission could require the Companies to post the data both ways – averaged over three months and averaged over 12 months, updated quarterly. The Companies stated that they object to this approach. The Companies maintained that they and the Public Staff should not be required to track two sets of service quality results for website posting. The Companies argued that not only would it be burdensome, but there is no compelling reason to post this data in two separate formats. The Companies maintained that this proposal will not motivate the companies to refrain from filing force majeure waivers any time a three-month's average is jeopardized by an act of God. The Companies asserted that, although the 12 months' average would still be available for consumers to review, no company will want to miss any measurement that is available for consumer review, and will be motivated to seek a waiver for missing three-month averages, even if the 12 month average is posted as well.

DISCUSSION

The Commission notes that in the *November 8, 2004 Order*, it reversed course on two specific results concerning the details of website posting that the Commission had, in fact, ordered in the *December 27, 2002 Order*. Specifically, the Commission:

(1) concluded that service quality results should be posted on the Commission's website only (and not the Public Staff's or each individual company's websites). The Commission had found on Page 32 of its *December 27, 2002 Order* that it could require ILECs and CLPs to post on their websites a pass/fail statement regarding each of the Rule R9-8 requirements, together with the amount of penalties levied against them or credits or refunds required of them with citation to that part of Rule R9-8 which gave rise to the penalty, credit, or refund.

(2) concluded that companies should not be required to post on their own websites (or on the Public Staff's or Commission's websites) the amount of penalties levied against them with citation to the service objective which gave rise to the penalty. The Commission had found on Page 32 of its *December 27, 2002 Order* that it could require ILECs and CLPs to post on their websites a pass/fail statement regarding each of the Rule R9-8 requirements, together with the amount of penalties levied against them or credits or refunds required of them with citation to that part of Rule R9-8 which gave rise to the penalty, credit, or refund.

First, the Companies asserted that it has been a long-standing practice of the Commission to encourage negotiations and consensus building; absent a significant and material reason to reject the recommendations of the parties, including the Public Staff and, to some extent, the Attorney General, it is unclear as to how or why the Commission reached its decision. The Commission has accepted and rejected various negotiations by the Parties in this docket; the concern with this docket is that all of the Parties, except possibly the Public Staff and Attorney General, have the same incentives concerning service quality. This docket is unique in that, by its nature, industry parties do not have conflicting goals and proposals. However, because the industry parties and the Public Staff, as a representative of the using and consuming public in North Carolina, have agreed that a 12-month average, updated quarterly, of service quality results is a reasonable and appropriate way to post service quality results for use by the public, the Commission will acquiesce in the negotiated position.

Second, the Companies maintained that there is no evidence that a quarterly average of service results is significantly more beneficial to customers than a 12-month rolling average which is updated quarterly. In fact, the Companies asserted, it is logical to believe that a consumer would be more interested in longer-term results as opposed to a quarter-by-quarter reporting result when considering a telecommunications carrier on the basis of service quality. The Companies argued that a 12-month rolling average, updated quarterly, would meet consumer needs, smooth out anomalies in reporting results and would not be unnecessarily burdensome to any party. The Companies maintained that it has been the considerable experience of Industry Task Force members that the vast majority of customers simply do not sign up for service with the intent of remaining on the network for just one quarter; providing customers with a tool that allows them to evaluate a complete year is far more indicative of the experience they will receive over the life of their service. The Commission does agree that a 12-month average would likely smooth out anomalies more so than a three-month average; however, the Commission is somewhat concerned that some of those anomalies could reflect circumstances where a company did not regularly provide service in accordance with Rule R9-8 standards with no legitimate or reasonable excuse.

Third, the Companies argued that quarterly averaging will only serve to fuel the need for carriers to file multiple force majeure waiver requests to smooth out anomalous results. The Companies asserted that the fact that the Commission has also declined to allow parties to post explanatory comments along with reported results will exacerbate the need for carriers to file more, not fewer, force majeure waiver requests going forward. The Companies maintained that, in all but one of the quarters set forth in the Commission's *November 8, 2004 Order*, there is a high risk of a force majeure event that could impact telecommunications companies: January through March – ice and snow; April through June – lower risk quarter; July through September – severe thunderstorms and hurricanes; and October through December - continued risk for hurricanes and then ice and snow. The Companies asserted that filing a force majeure waiver is burdensome not only to telecommunications carriers but also to the Public Staff and the Commission. The Commission agrees with the Attorney General that the Companies' argument on this point is not persuasive. The Commission notes that several ILECs including BellSouth, Carolina, Central, and North State Communications have self-effectuating penalty provisions in their price regulation plans. Under these provisions, if the statewide, 12-month average for certain measures falls below the specific standard, the Company will pay penalties. The Commission doubts that a company will risk having to pay penalties for missed service quality results by not filing a force majeure waiver request when a force majeure event occurs even if a 12-month average is adopted.

In summary, the Commission has concerns and reservations about posting a 12-month average of service quality results on the website. However, the industry parties and the Public Staff, as a representative of the using and consuming public, have negotiated using a 12-month average, updated quarterly. Therefore, the Commission finds it appropriate to accept the negotiation of the parties on this matter and adopt a 12-month average, updated quarterly, for posting service quality results on the Commission's website.

Since revised Rule 9-8 became effective on July 1, 2004, and the Commission, to date, only has service quality results under revised Rule R9-8 from July 2004 through March 2005, the Commission finds that website posting of service quality results will occur as soon as possible after the service quality reports reflecting results from April, May, and June 2005 are filed with the Commission in order to utilize a 12-month average of service quality results.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission finds it appropriate to grant the Motion for Reconsideration, accept the negotiation of the parties on this matter, and adopt a 12-month average, updated quarterly, for posting service quality results on the Commission's website.

2. That website posting of service quality results shall occur as soon as possible after the service quality reports reflecting results from April, May, and June 2005 are filed with the Commission in order to utilize a 12-month average of service quality results.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of June, 2005

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

bp060205.01

DOCKET NO. P-100, SUB 133d

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of General Proceeding to Determine Permanent Pricing for Unbundled Network Elements	))))	ORDER APPROVING AND ADOPTING FINAL UNE RATES FOR BELLSOUTH

BY THE CHAIR: On December 30, 2003, the Commission issued its *Order Adopting Permanent Unbundled Network Element (UNE) Rates for BellSouth Telecommunications, Inc.* (BellSouth).

On August 20, 2004, the Federal Communications Commission (FCC) released its *Order and Notice of Proposed Rulemaking* in WC Docket No. 04-313 and CC Docket No. 01-338 (*Interim Rules Order or IRO*). In its Order, the FCC stated

> . . . First, on an interim basis, we require incumbent local exchange carriers (LECs) to continue providing unbundled access to switching, enterprise market loops, and dedicated transport under the same rates, terms and conditions that applied under their interconnection agreements as of June 15, 2004. These rates, terms, and conditions shall remain in place until the earlier of the effective date of final unbundling rules promulgated by the Commission or six months after Federal Register publication of this Order, except to the extent that they are or have been superseded by (1) voluntarily negotiated agreements, (2) an intervening Commission order affecting specific unbundling obligations (e.g., an order addressing a pending petition for reconsideration), or (3) (with respect to rates only) a state public utility commission order raising the rates for network elements . . . [Paragraph 1 with footnotes omitted]

On August 26, 2004, the Commission issued its *Order Ruling on Motions for Reconsideration.* The *August 26, 2004 Order* found in Ordering Paragraph No. 2, "that the rates produced from the Commission's *December 30, 2003 Order* were effective as of December 30, 2003, unless an interconnection agreement indicates that the parties intended otherwise." Further, Ordering Paragraph No. 3 stated, "that the rates produced from this Order, reflecting changes from the *December 30, 2003 Order* after reconsideration, are effective as of August 26, 2004."

On September 3, 2004, the Commission issued its *Order Addressing Certain BellSouth Recurring and Nonrecurring Charges.* The Commission instructed BellSouth to resubmit its cost studies and supporting documentation by October 4, 2004 and requested the Public Staff to file comments on the studies by October 25, 2004.

On October 4, 2004, BellSouth filed its cost studies and documentation based on the conclusions the Commission reached in its *September 3, 2004 Order, August 26, 2004 Order,* and *December 30, 2003 Order.*

On October 28, 2004, BellSouth refiled its cost studies in order to include the central office equipment Sales Tax Adjustment which was inadvertently omitted from the October 4, 2004 filing.

On November 2, 2004, the Public Staff filed its comments on BellSouth's rate filings. The Public Staff stated that it had reviewed the filings made by BellSouth on October 4 and October 28, 2004. The Public Staff also stated that it believes that the rates reflected in BellSouth's October 28, 2004 filing incorporate the changes required by the Commission's Orders of December 30, 2003, August 26, 2004, and September 3, 2004.

On November 24, 2004, the Commission issued its *Order Ruling on Exceptions.* In its Order, the Commission rescinded Ordering Paragraph No. 2 of the *August 26, 2004 Order* and the conclusion that the new BellSouth UNE rates were available to competing local providers (CLPs) on December 30, 2003, unless an interconnection agreement indicated that the parties intended otherwise.

On November 29, 2004, the Commission issued its *Order Concerning BellSouth's Unbundled Network Element Rates.* In its Order, the Commission found it appropriate to request BellSouth to file by December 10, 2004 a complete UNE price list with an effective date of August 26, 2004 which was consistent with the Commission's orders in this docket and with the interim rules set in place by the FCC in its *IRO*. The Public Staff was requested to evaluate and comment on BellSouth's filing by December 20, 2004.

On December 7, 2004, DIECA Communications, Inc., d/b/a Covad Communications Company (Covad) filed a Motion to Postpone Filing of UNE Rates with respect to BellSouth's December 10, 2004 UNE price list filing until after the FCC released the final UNE rules. By Order dated December 9, 2004, the Commission granted Covad's Motion, thereby, requiring BellSouth to file its complete UNE price list as soon as practicable after the FCC issued its final UNE ruling.

On February 4, 2005, the FCC released its *Order on Remand (Triennial Review Remand Order or TRRO).*

On March 7, 2005, AT&T Communications of the Southern States, LLC (AT&T) and MCImetro Access Transmission Services, LLC (MCI) filed a Motion for Order Directing BellSouth to File Conforming Rates wherein AT&T and MCI requested that the Commission (a) direct BellSouth to file its conforming price list and cost studies immediately, and (b) allow parties to this proceeding, besides the Public Staff, to comment on BellSouth's price list and studies prior to Commission approval.

On March 18, 2005, BellSouth filed its North Carolina UNE Price List which it asserted was consistent with the Commission's orders in this docket as well as the FCC's *Triennial Review Order (TRO), IRO,* and *TRRO.*

On March 23, 2005, the Commission issued its *Order Requesting Comments on BellSouth's Unbundled Network Element Rates.* In its Order, the Commission requested interested parties, specifically including the Public Staff, to file comments on BellSouth's March 18, 2005 UNE Price List by no later than Monday, April 11, 2005.

On April 6, 2005, the Public Staff made an oral motion for an extension of time to file comments from Monday, April 11, 2005 to Monday, April 25, 2005. By Order dated April 7, 2005, the oral motion was granted.

On April 22, 2005, the Public Staff and BellSouth made a joint oral motion for an extension of time to file comments by no later than Monday, May 2, 2005. By Order dated April 22, 2005, the joint oral motion was granted.

On April 29, 2005, Covad made an oral motion for extension of time to file comments on BellSouth's proposed line sharing and line splitting rates by no later than May 9, 2005.

Also on April 29, 2005, BellSouth filed a revised North Carolina UNE Price List and wirecenter to UNE rate zone mapping list. BellSouth noted that its April 29, 2005 Filing replaced in its entirety the filing made by BellSouth in this docket on March 18, 2005 and was the result of negotiations between BellSouth and the Public Staff.

By Order dated May 2, 2005, Covad's oral motion was granted. Also on May 2, 2005, Covad filed a Motion for Extension of Time which merely recited in written form Covad's April 29, 2005 oral motion.

On May 3, 2005, BellSouth filed a second revised North Carolina UNE Price list and wirecenter to UNE rate zone mapping list. BellSouth stated that its May 3, 2005 filing replaces in its entirety the revised filing made by BellSouth in this docket on April 29, 2005 and was the result of additional negotiations.

On May 9, 2005, the Public Staff filed its comments on BellSouth's May 3, 2005 UNE Price List. The Public Staff stated that it had completed its review of the second revised UNE Price List and took issue with only one aspect of the second revised UNE Price List.

Specifically, the Public Staff stated, certain rate elements associated with long copper loops have been excluded from BellSouth's proposed UNE Price List including rate elements A.13.7 (2-Wire Copper Loop – long), A.13.14 (CLEC to CLEC Conversion 2-Wire Copper Loop – long), A.14.7 (4-Wire Copper Loop – long), and A.14.14 (CLEC to CLEC Conversion 4-Wire Copper Loop – long). The Public Staff commented that it understands that BellSouth excluded these rate elements based on its contention that it is not required to provide these elements pursuant to the FCC's *TRRO.*

The Public Staff noted that this matter is currently before the Commission in the arbitration proceeding heard recently in Docket Nos. P-772, Sub 8, P-913, Sub 5, P-989, Sub 3, P-824, Sub 6, and P-1202, Sub 4 (Docket Nos. P-772, Sub 8, et. al.). The Public Staff stated that Matrix Item Nos. 36, 37, and 38 relate to the question of whether BellSouth should be required to provide loops and any associated line conditioning when the loops are longer than 18,000 feet. The Public Staff maintained that BellSouth contended that since it does not provide such conditioned loop to its own customers, it has no obligation to do so for CLPs.

The Public Staff asserted that BellSouth is obligated to provide and condition loops of any length since the FCC's rules define line conditioning as removing disruptive devices on loops without any limitation on the length of the loop. The Public Staff opined that this obligation to condition loops of any length is clearly pointed out by the FCC in footnote 1946 of the TRO. The Public Staff included by reference the evidence and conclusions for Matrix Item Nos. 36, 37, and 38 contained in its Proposed Recommended Arbitration Order filed in Docket Nos. P-772, Sub 8, et. al. for additional support of its position.

The Public Staff maintained that consistent with that point of view, the Public Staff believes that the Commission should require BellSouth to include rate elements A.13.7, A.13.14, A.14.7, and A.14.14 in its UNE Price List.

WHEREUPON, the Chair now reaches the following

CONCLUSIONS

The Chair finds it appropriate to approve BellSouth's UNE Price List as filed on May 3, 2005. The Chair believes that a decision at this point in time on rate elements A.13.7, A.13.14, A.14.7, and A.14.14 would presuppose the Commission's pending decision in Docket Nos. P-772, Sub 8, et. al. The Commission will address any appropriate rates for these four elements by further order.

Based upon the foregoing, the UNE Price List filed on May 3, 2005 by BellSouth is hereby approved and adopted.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of May, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp051905.01

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 ADOPTING FINAL AUDIT) SCOPE, REQUIRING BELLSOUTH) TO FILE A RFP, AND CONTINUING) TO DELAY ANNUAL REVIEW

BY THE COMMISSION: On May 22, 2002, the Commission issued its *Order Concerning Performance Measurements and Enforcement Mechanisms* for BellSouth Telecommunications, Inc. (BellSouth).

On May 29, 2003, the Commission issued its *Order Addressing Which Submeasures to Include in BellSouth's Remedy Plan and Establishing an Effective Date of August 1, 2003 for BellSouth's SQM and Remedy Plan.* The *May 29, 2003 Order* resolved all outstanding issues and is considered the "final order" on BellSouth's Service Quality Measurement (SQM) plan and Self-Effectuating Enforcement Mechanism (SEEM) plan (collectively, the Plans).

On August 1, 2003, BellSouth filed a copy of its SQM plan and SEEM plan, effective August 1, 2003. Appendix C of the SQM plan requires annual third-party audits of BellSouth's performance measurement plan, and Appendix D requires annual review cycles of the SQM and SEEM plans.

On July 30, 2004, the Competitive Local Provider (CLP) Coalition[1] filed its Motion for Postponement of the Annual Audit and Review.

On August 3, 2004, the Commission issued its *Order Requesting Comments on Motion for Postponement.* The Commission requested initial comments by August 17, 2004 and reply comments by August 31, 2004.

On August 17, 2004, BellSouth filed its initial comments. Reply comments were filed on August 31, 2004 by the CLP Coalition and the Public Staff.

On October 19, 2004, the Commission issued its *Order Postponing Annual Review and Initiating Annual Audit.* The Commission found it appropriate to (1) postpone the first annual review of the BellSouth North Carolina SQM and SEEM Plans until further order and instructed the parties to file a joint status report on the Florida and Georgia audits and the Florida and Tennessee reviews on January 24, 2005; and (2) initiate the first annual audit as soon as possible by directing BellSouth and the CLPs to file recommendations concerning the scope and conduct of the initial audit no later than November 8, 2004 and directing BellSouth, the CLPs, and the Public Staff to file responses to the proposals no later than December 8, 2004. The Commission further instructed BellSouth and the CLPs to select the third-party auditor and to file their recommendation with the Commission for approval no later than December 20, 2004.

[1] AT&T Communications of the Southern States, LLC (AT&T), DIECA Communications, d/b/a Covad Communications Company (Covad), MCI Metro Access Transmission Services, LLC, and MCI WorldCom Communications, Inc. (MCI).

On December 20, 2004, the Commission issued its *Order Concerning Scope and Conduct of First SQM/SEEM Audit* wherein the Commission tentatively adopted the audit scope proposed by the Public Staff in Appendix A to its December 8, 2004 filing. BellSouth and the CLP Coalition were instructed to file any objections to the tentative audit scope by no later than Monday, January 10, 2005 by including a redlined version of the tentative audit scope and a written explanation of the proposed changes to the tentative audit scope in both hardcopy form and electronic format in Word.

Also on December 20, 2004, BellSouth filed its recommendation regarding an appropriate auditor to conduct the initial audit of the North Carolina SQM and SEEM Plans and the CLP Coalition[1] filed its recommendation for a third-party auditor.

On December 30, 2004, BellSouth filed its Petition for Establishment of a New Performance Assessment Plan. BellSouth requested that the Commission supersede and replace the Current Plan with the Proposed Plan attached to its Petition.

On January 10, 2005, BellSouth filed its Comments regarding the audit scope proposed by the Public Staff, and on January 11, 2005, the CLP Coalition[2] filed its Joint Filing of redlined Appendix A regarding the scope of the SQM/SEEM audit.

On January 24, 2005, BellSouth and the CLP Coalition filed their joint status report on the Florida and Georgia audits and the Florida and Tennessee reviews.

In this Order, the Commission will address the matters at issue which are categorized into three areas as follows:

Section I addresses the audit scope;
Section II addresses the selection of an auditor; and
Section III addresses BellSouth's December 30, 2004 Petition for Establishment of a New Performance Assessment Plan.

SECTION I – AUDIT SCOPE

JANUARY 10 AND 11, 2005 COMMENTS CONCERNING SCOPE OF AUDIT

BELLSOUTH: BellSouth provided a redlined version of the Public Staff's proposed audit scope. BellSouth noted that the redlined version attached to its comments were the result of a collaborative effort between BellSouth and Covad to review and redline the Public Staff's proposed audit scope. BellSouth stated that its understanding is that Covad's involvement in redlining the Public Staff's proposed audit scope was made on behalf of the CLP Coalition. BellSouth maintained that the proposed revisions are primarily designed to: (1) focus the initial audit of the Plans on 2004 data; (2) provide for exceptions to certain Plan audit areas, specifically to the areas of calculation compliance, remedy calculations, and reporting, subject to the materiality criteria set forth in the Plan's reposting criteria; (3) protect proprietary information; and (4) clarify that within 30 days of the release of the auditor's final report,

[1] AT&T, Covad, and MCImetro Access Transmission Services, LLC.

[2] AT&T, Covad, ITC^DeltaCom, Inc., and MCImetro Access Transmission Services, LLC.

BellSouth will file a comprehensive action plan for addressing all material exceptions, if any, identified in such report.

BellSouth requested that the Commission adopt the audit scope attached to its January 10, 2005 filing.

CLP COALITION: The CLP Coalition provided a copy of its redlined version of the Public Staff's proposed audit scope. The CLP Coalition reflected the exact same proposed revisions as BellSouth proposed. The CLP Coalition listed each of the proposed revisions along with a brief explanation of each proposed revision.

DISCUSSION

In the Commission's *December 20, 2004 Order*, the Commission tentatively adopted the Public Staff's proposed audit scope attached to its December 8, 2004 Comments as Appendix A. On January 10 and 11, 2005, BellSouth and the CLP Coalition filed a redlined version of the tentative audit scope which reflects a few specific changes to the tentative audit scope. A copy of the redlined version of the tentative audit scope filed by BellSouth and the CLP Coalition is attached hereto, as Appendix A. BellSouth and the CLP Coalition agreed on the proposed changes to the tentative audit scope.

CONCLUSIONS

The Commission has reviewed the proposed changes of BellSouth and the CLP Coalition and finds it appropriate to adopt those changes. Therefore, the Commission adopts the initial audit scope for the North Carolina SQM and SEEM Plan audit attached hereto, as **Appendix B.**

SECTION II – SELECTION OF AN AUDITOR

RECOMMENDATIONS ON THE SELECTION OF AN AUDITOR

BELLSOUTH: BellSouth recommended that PriceWaterhouseCoopers LLP (PwC) be selected to conduct the initial audit of the Plans. BellSouth noted that despite good faith efforts, BellSouth and the CLP Coalition were unable to agree upon the selection of an auditor to conduct the initial audit of the Plans. BellSouth noted that it has concerns about Liberty Consulting Group's (Liberty's)[1] ability to contemporaneously conduct and complete the Florida SQM and SEEM audit and commence a North Carolina audit.

BellSouth noted that PwC is close to completing an audit of the Georgia SEEM Plan. BellSouth noted that both the North Carolina and Georgia SEEM Plans are transaction-based remedy calculation plans. Further, BellSouth noted, the North Carolina and Georgia SEEM Plans have the same level of product disaggregation. As such, BellSouth maintained, PwC has the requisite knowledge and understanding necessary to audit the Plan, including a strong understanding of the processes used to calculate and pay SEEM fees.

BellSouth also argued that because PwC should complete the Georgia SEEM audit in December 2004, PwC can deploy many of the same resources who have been working on the

[1] The CLP Coalition has proposed that Liberty be the third-party auditor.

Georgia SEEM audit to begin work on the North Carolina audit. BellSouth further commented that these resources will be dedicated full time to the North Carolina audit. BellSouth also noted that PwC has indicated that it can commence a North Carolina audit in early January 2005.

BellSouth pointed out that the Commission has found that it is imperative and appropriate to commence the North Carolina audit as soon as possible. BellSouth argued that the selection of a well known and well respected company such as PwC to conduct the North Carolina audit will allow the Commission to achieve its objective in an efficient and timely manner.

BellSouth noted that in response to its inquiries, Liberty has proposed using the same audit team that is conducting the audit of the Florida SQM and SEEM Plans to conduct the North Carolina audit. BellSouth stated that the Florida audit is scheduled to be completed around April 2005. BellSouth asserted that it is unclear how Liberty would be able to conduct both audits simultaneously utilizing the same personnel. Further, BellSouth noted, Liberty has indicated that it could begin the North Carolina audit in February 2005, a month later than PwC's start date.

CLP COALITION: The CLP Coalition opposes BellSouth's recommendation of PwC as the choice for auditor for two reasons: (1) from the CLPs' point of view, BellSouth unilaterally selected PwC as the third-party auditor for the Georgia SEEM audit; and (2) in sharp contrast to the Georgia Request for Proposal (RFP) process is the recent RFP process in Florida that was conducted by the Florida Commission Staff, and which resulted in Liberty being chosen as the third-party auditor.

The CLP Coalition asserted that although PwC was selected through a formal RFP process in Georgia, it was BellSouth who made that decision by narrowing the choice of vendors from five to three. Then, the CLP Coalition maintained, after those three vendors made their formal presentations to BellSouth and the Georgia Commission Staff, it was again BellSouth who, without any input from the CLPs, informed the Georgia Public Service Commission (PSC) in a letter dated August 27, 2004 and filed in Docket Nos. 7892-U and 8354-U that they had chosen PwC as the recommended auditor.

The CLP Coalition stated that unlike the Georgia selection process, in Florida the CLPs were given an opportunity to participate and provide input toward the final decision of an auditor early in the selection process versus being brought in essentially after the fact, as was the case in Georgia.

The CLP Coalition recommended that Liberty be chosen as the third-party auditor to conduct the North Carolina SEEM audit. The CLP Coalition noted that its recommendation was influenced by a number of issues. First, the CLP Coalition maintained, Liberty was chosen as the third-party auditor to conduct the Florida SEEM audit through a collaborative effort involving BellSouth, the Florida Commission Staff, and a number of representative CLPs operating in Florida. The CLP Coalition noted that Liberty underwent the formal BellSouth RFP process and the CLPs along with BellSouth and the Florida Commission Staff were given the chance to comment on Liberty's abilities and qualifications with respect to the SEEM audit. The CLP Coalition stated that the CLPs were afforded the courtesy of providing input from the beginning of the selection process through the final recommendation of the preferred auditor.

The CLP Coalition also stated that it believes that each prospective vendor should be allowed the opportunity to submit a proposal for the review and consideration of all involved parties. The CLP Coalition argued that neither the carrier parties nor any other person should make general assumptions regarding the availability of any vendor involved in the RFP process; each vendor should be afforded the opportunity to respond to requests concerning the services they can provide and in what time frame they can provide them.

The CLP Coalition recommended that the Commission review the issues cited by the CLP Coalition regarding its recommendation for the third-party auditor and give Liberty the chance to bid for the North Carolina SEEM audit. The CLP Coalition noted that the Commission along with BellSouth and the CLP Coalition can then review the proposals and collaboratively determine the best choice of vendor and the best timeline for conducting the North Carolina audit.

The CLP Coalition stated that it appreciates the Commission's efforts to promote a fair and unbiased audit. The CLP Coalition strongly urged the Commission to continue to play an active role in managing the audit process.

DISCUSSION

The Commission notes that BellSouth and the CLP Coalition have not reached an agreement on the selection of a third-party auditor. BellSouth has proposed PwC and the CLP Coalition has proposed Liberty. The Commission notes that the adopted audit scope states in Section II – Conduct of the Audit:

> BellSouth and the CLP Coalition will jointly select an auditor or auditors to carry out the North Carolina SQM/SEEM audit and provide this information to the Commission within the prescribed deadline. [**Commission Note:** The deadline was December 20, 2004.] If BellSouth and the CLP Coalition advise the Commission that they cannot agree on the choice of auditor(s), the Commission will either select the auditor(s) or establish a procedure for BellSouth to follow in order to select the auditor(s). The auditor(s) so selected will be subject to Commission approval. Subject to an appropriate protective agreement/order or other measures designed to protect the disclosure of proprietary information, BellSouth will file copies of any agreement(s) reached between it and the auditor(s) in connection with the North Carolina audit, and will promptly advise the Commission of any proposed amendments to the agreement(s) and secure Commission approval of those changes.
>
> In the event the Commission requires the submission of bids from potential auditors, BellSouth will draft a comprehensive Request for Proposal (RFP) incorporating this document, and submit the RFP for Commission approval prior to soliciting bids. BellSouth will issue the RFPs, analyze the responses, and provide the Commission with copies of those responses and with its specific recommendations concerning auditor selection. The Commission will then select the auditor(s) to conduct the audit.

BellSouth noted that PwC has been conducting the audit in Georgia and the CLP Coalition noted that Liberty has been conducting the audit in Florida. Since BellSouth and the CLP Coalition have not agreed on the choice of auditor(s), under the adopted audit scope, the Commission can either (1) select the auditor(s); or (2) establish a procedure for BellSouth to follow in order to select the auditor(s). The Commission simply does not have enough information available to it to select a third-party auditor at this point in time. Therefore, the Commission finds that it has no other choice than to require a RFP process in order to select an auditor.

Under the adopted audit scope, BellSouth will be required to draft a comprehensive RFP and submit the RFP to the Commission for approval prior to soliciting bids. The Commission finds it appropriate to require BellSouth to file its proposed RFP by no later than Monday, February 14, 2005. The CLP Coalition and the Public Staff should file any comments on the RFP by no later than Monday, February 21, 2005. The Commission will then issue an Order concerning BellSouth's proposed RFP.

CONCLUSIONS

BellSouth shall file its proposed RFP by no later than Monday, February 14, 2005. The CLP Coalition and the Public Staff shall file any comments on the RFP by no later than Monday, February 21, 2005.

SECTION III – BELLSOUTH'S PETITION FOR NEW PLAN

On December 30, 2004, BellSouth filed its Petition for the Establishment of a New Performance Assessment Plan. BellSouth stated that pursuant to the Plans review provisions set forth in the Current Plans and subject to the Commission's *October 18, 2004 Order*, BellSouth filed its Petition requesting the Commission to issue an Order implementing a new performance assessment plan for BellSouth in North Carolina. BellSouth filed its Proposed Plans as Exhibits A through D of its Petition.

BellSouth asserted that the Proposed Plans are a more effective and efficient monitoring and enforcement mechanism when compared to the Current Plans. BellSouth maintained that by adopting the Proposed Plans, the Commission will implement a more efficient monitoring plan that will continue to ensure that BellSouth's performance remains at a satisfactory and nondiscriminatory level, and will establish a more effective remedy payment plan wherein penalties are rationally related to the level of BellSouth's performance in North Carolina.

BellSouth asserted that the Current Plan's fee schedule generates exorbitant penalties that bear no rational relationship to performance provided to CLPs or the service charges associated with such penalties. BellSouth also maintained that the Current SQM Plan contains metrics and submetrics that serve no useful purpose and that eliminating such metrics will improve the Plan's monitoring capability.

On January 24, 2005, BellSouth and the CLP Coalition jointly filed a status report on the Florida and Georgia audits and the Florida and Tennessee reviews as required by the Commission in its *October 19, 2004 Order*.

DISCUSSION

The Commission stated in its *October 19, 2004 Order* that the first annual review of the BellSouth North Carolina SQM and SEEM plans was postponed until further order. The Commission does not see any necessity in altering this finding. The Commission will closely study and consider the joint status report filed on January 24, 2005 and will continue to postpone the review until further order. At the beginning of the review cycle, yet to be determined, the Commission will solicit proposed revisions, if any, from the CLPs. BellSouth will also be given the opportunity to file additional proposed revisions or continue to propose the revisions outlined in its December 30, 2004 Petition.

CONCLUSIONS

The annual review continues to be postponed until further Commission order. At the beginning of the review cycle, the Commission will solicit proposed revisions, if any, from the CLPs; and BellSouth will be given the opportunity to file additional proposed revisions or continue to propose the revisions outlined in its December 30, 2004 Petition.

IT IS, THEREFORE, ORDERED, as follows:

1. That the Commission adopts the audit scope presented in Appendix B, as attached hereto.

2. That BellSouth shall file its proposed RFP by no later than Monday, February 14, 2005. The CLP Coalition and the Public Staff shall file any comments on the RFP by no later than Monday, February 21, 2005.

3. That the annual review continues to be postponed until further Commission order. At the beginning of the review cycle, yet to be determined, the Commission will solicit any proposed revisions from the CLPs; and BellSouth will be given the opportunity to file additional proposed revisions or continue to propose the revisions outlined in its December 30, 2004 Petition.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of January, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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APPENDIX A

NORTH CAROLINA SQM/SEEM AUDIT

REDLINED VERSION OF TENTATIVE AUDIT SCOPE AS PROPOSED BY BELLSOUTH AND THE CLP COALITION

I. SCOPE OF THE AUDIT

The North Carolina SQM/SEEM audit will include a compliance audit of BellSouth's PMQAP; an audit to determine the completeness and accuracy of BellSouth's SQM data as reported by PMAP; and an audit to determine the completeness and accuracy of BellSouth's SEEM data and SEEM payments as reported in PARIS.

The versions of BellSouth's North Carolina SQM/SEEM plans to be audited are the BellSouth Service Quality Measurement Plan (SQM), Version 1.00, issued August 1, 2003, and the North Carolina SEEM Administrative Plan, Version 1.0, issued August 1, 2003. (If BellSouth has amended either of these plans since August 1, 2003, it should provide updated SQM/SEEM pages to the Commission and Public Staff, and highlight and explain any changes that were made.)

There are seven major areas for review in the audit:

1. Documentation
2. Data Validation
3. Calculation Compliance
4. Remedy Calculations and Payments
5. Adjustments
6. Reporting
7. Metric Change Management Process.

A detailed outline of the scope for each area of review is provided below.

1. Documentation

a. Verify that supporting documentation for replication of PMAP 4.0 and PARIS 2.0 job flows are sufficient, clear, and complete.
b. Verify that documented procedures exist for the metric change process and are sufficient, clear, and complete.
c. Verify that BellSouth is in compliance with SQM and SEEM documentation and other Commission orders.

2. Data Validation

a. Verify appropriate transaction flow from files in the Regulatory Ad-Hoc Data System ("RADS") to the Performance Measurement Analysis Platform ("PMAP") Data Warehouse, SQM/SRS, and PARIS data marts.
b. Verify the accuracy of data fields in the PMAP Data Warehouse, SQM/SRS, and PARIS.

c. Verify the assignment of CLP and BellSouth retail transactions to the appropriate cells for parity sub-measures where applicable. Verify that BellSouth is in compliance with PMQAP for data validation processes.

3. Calculation Compliance

a. For selected individual CLPs and aggregate SQM/SRS and PARIS reports, verify the accuracy of SQM/SRS reports and verify that PARIS accurately determines measurement compliance from the data in the PMAP warehouse. The auditor(s) may need to:
    i. Verify the correct application of benchmark standards.
    ii. Verify the accuracy of computed benchmark results.
    iii. Verify accurate determinations of compliance.
    iv. Verify that modified z scores are accurate for SQM/SRS reports.
    v. Verify correct application of retail parity measures.
    vi. Verify accurate determinations of compliance for SRS/SQM and SEEM evaluation purposes.
b. For parity measures in SEEM, the auditor(s) may need to:
    i. Verify the accuracy of truncated z scores in SEEM.
    ii. Verify the accuracy of delta values.
    iii. Verify the accuracy of balancing critical values.

4. Remedy Calculations and Payments

a. Verify that the appropriate fee was utilized in calculation of remedies.
b. Validate the accuracy of remedy payments made to CLPs compared to remedies calculated in PARIS.
c. Validate the accuracy of remedy payments made to the State of North Carolina compared to the remedies calculated in PARIS.
d. Verify the correct implementation of administrative penalty provisions.

5. Adjustments

a. Identify the underlying causes for adjustments to SEEM payments ~~and determine whether those causes are appropriate~~.
b. Determine if the required adjustments are appropriate.
c. Validate that adjustment amounts are accurate.
d. Validate that adjustments comply with all required time frames.
e. Verify that adjustments were correctly made and completely applied.

6. Reporting

a. Validate the accuracy and completeness of data reported in SQM/SRS and PARIS reports.
b. Verify that the Tier 1 Transmitted Payment accurately reflects the PARIS calculation.
c. Verify that the Tier 2 State Payment accurately reflects the PARIS calculation.

7. Metric Change Management Process

a. Verify that BellSouth is in compliance with the PMQAP for the metric change management processes.
b. Validate compliance with established procedures for the metric change notification process.
c. Verify that changes to metrics are accurate and consistent with all SQM requirements.
d. Verify the accuracy of impact statements in metric change notification reports.

Note: Items 2 through ~~6~~ 7 above are only applicable to the measures within the scope of the audit.

At a minimum, the audit will evaluate BellSouth's performance on the following North Carolina metrics:

Measure	Description
O-3/O-4	Percent Flow-Through Service Request Summary/Detail
O-9	Firm Order Confirmation Timeliness
P-3	Percent Missed Installation Appointments
P-4	Average Completion Interval (OCI) & Order Completion Interval Distribution
P-6/P-6C	Coordinated Customer Conversions Interval
P-8	% Provisioning Troubles within 30 Days of Service Order Completion
M&R-1	Missed Repair Appointments
M&R-2	Customer Trouble Report Rate
M&R-3	Maintenance Average Duration
M&R-4	Percent Repeat Troubles within 30 Days
M&R-5	Out of Service (OOS) > 24 Hours
B-1	Invoice Accuracy.

The auditor(s) will determine the specific months to be audited for each audit area and will use current (2004/~~2005~~) data to complete statistical evaluations and testing of BellSouth's SQM performance measurements and SEEM payments. The auditor(s) must audit at least two months of data for each selected metric within a given audit area. The Commission may, at its discretion, ask the auditor(s) to audit additional metrics or additional timeframes as deemed necessary.

For the SEEM audit, statistical and testing methods should include validation of data in accordance with the methods and formulas provided in Appendices C, D, and E of BellSouth's North Carolina SEEM Administrative Plan, Version 1.0, dated August 1, 2003. ~~The auditor(s) will determine materiality criteria for each review area, subject to approval by the Commission.~~ For items 3, 4 and 6 above, the materiality criteria for exceptions are those listed in the Reposting Policy. Staff and the selected auditor will jointly determine materiality criteria for other items.

II. CONDUCT OF THE AUDIT

BellSouth and the CLP Coalition will jointly select an auditor or auditors to carry out the North Carolina SQM/SEEM audit and provide this information to the Commission within the prescribed deadline. If BellSouth and the CLP Coalition advise the Commission that they cannot agree on the choice of auditor(s), the Commission will either select the auditor(s) or establish a procedure for BellSouth to follow in order to select the auditor(s). The auditor(s) so selected will be subject to Commission approval. Subject to an appropriate protective agreement/order or other measures designed to protect the disclosure of proprietary information, BellSouth will file copies of any agreement(s) reached between it and the auditor(s) in connection with the North Carolina audit, and will promptly advise the Commission of any proposed amendments to the agreement(s) and secure Commission approval of those changes.

In the event the Commission requires the submission of bids from potential auditors, BellSouth will draft a comprehensive Request for Proposal (RFP) incorporating this document, and submit the RFP for Commission approval prior to soliciting bids. BellSouth will issue the RFPs, analyze the responses, and provide the Commission with copies of those responses and with its specific recommendations concerning auditor selection. The Commission will then select the auditor(s) to conduct the audit.

At least two weeks prior to commencing the audit, the auditor(s) will make a presentation to the Commission staff, Public Staff, BellSouth, and CLP Coalition to outline the procedures it will follow in conducting the audit, to answer questions, and to propose specific time frames for the audit. During the course of the audit, the auditor(s) will file detailed progress reports with the Chief Clerk, Commission staff, Public Staff, BellSouth, and CLP Coalition every 30 days until the audit is completed.

At the conclusion of the audit, the auditor(s) will prepare and provide to the Chief Clerk, Commission staff, Public Staff, BellSouth, and CLP Coalition a final report detailing the specific findings and conclusions from the audit, and identifying any exceptions noted during the audit. The report will present recommendations for expeditiously resolving these exceptions. ~~The auditor(s) will continue to pursue the resolution of these exceptions and file a detailed report with the Chief Clerk, Commission staff, Public Staff, BellSouth, and CLP Coalition every 30 days until all exceptions have been resolved.~~ BellSouth will continue to pursue the resolution of any material exceptions that remain open or unresolved, after the audit has been completed and the final report released. Within thirty (30) days of the date that the auditor releases the final report, BellSouth will agree to prepare a comprehensive action plan for resolving any material exceptions that remain open after the release of the auditor's final report. Such action plan will require the Commission's explicit approval and will include, for each material open exception, a detailed description of the actions required and a timeline within which to resolve each exception. BellSouth agrees to file the action plan, in its entirety, in the North Carolina Performance Measures docket (P-100, Sub 133k).

APPENDIX B

NORTH CAROLINA SQM/SEEM AUDIT

COMMISSION-APPROVED AUDIT SCOPE

I. SCOPE OF THE AUDIT

The North Carolina SQM/SEEM audit will include a compliance audit of BellSouth's PMQAP; an audit to determine the completeness and accuracy of BellSouth's SQM data as reported by PMAP; and an audit to determine the completeness and accuracy of BellSouth's SEEM data and SEEM payments as reported in PARIS.

The versions of BellSouth's North Carolina SQM/SEEM plans to be audited are the BellSouth Service Quality Measurement Plan (SQM), Version 1.00, issued August 1, 2003, and the North Carolina SEEM Administrative Plan, Version 1.0, issued August 1, 2003. (If BellSouth has amended either of these plans since August 1, 2003, it should provide updated SQM/SEEM pages to the Commission and Public Staff, and highlight and explain any changes that were made.)

There are seven major areas for review in the audit:

1. Documentation
2. Data Validation
3. Calculation Compliance
4. Remedy Calculations and Payments
5. Adjustments
6. Reporting
7. Metric Change Management Process.

A detailed outline of the scope for each area of review is provided below.

1. Documentation

a. Verify that supporting documentation for replication of PMAP 4.0 and PARIS 2.0 job flows are sufficient, clear, and complete.
b. Verify that documented procedures exist for the metric change process and are sufficient, clear, and complete.
c. Verify that BellSouth is in compliance with SQM and SEEM documentation and other Commission orders.

2. Data Validation

a. Verify appropriate transaction flow from files in the Regulatory Ad-Hoc Data System ("RADS") to the Performance Measurement Analysis Platform ("PMAP") Data Warehouse, SQM/SRS, and PARIS data marts.
b. Verify the accuracy of data fields in the PMAP Data Warehouse, SQM/SRS, and PARIS.
c. Verify the assignment of CLP and BellSouth retail transactions to the appropriate cells for parity sub-measures where applicable. Verify that BellSouth is in compliance with PMQAP for data validation processes.

3. Calculation Compliance

a. For selected individual CLPs and aggregate SQM/SRS and PARIS reports, verify the accuracy of SQM/SRS reports and verify that PARIS accurately determines measurement compliance from the data in the PMAP warehouse. The auditor(s) may need to:
   vii. Verify the correct application of benchmark standards.
   viii. Verify the accuracy of computed benchmark results.
   ix. Verify accurate determinations of compliance.
   x. Verify that modified z scores are accurate for SQM/SRS reports.
   xi. Verify correct application of retail parity measures.
   xii. Verify accurate determinations of compliance for SRS/SQM and SEEM evaluation purposes.

b. For parity measures in SEEM, the auditor(s) may need to:
   iv. Verify the accuracy of truncated z scores in SEEM.
   v. Verify the accuracy of delta values.
   vi. Verify the accuracy of balancing critical values.

4. Remedy Calculations and Payments

a. Verify that the appropriate fee was utilized in calculation of remedies.
b. Validate the accuracy of remedy payments made to CLPs compared to remedies calculated in PARIS.
c. Validate the accuracy of remedy payments made to the State of North Carolina compared to the remedies calculated in PARIS.
d. Verify the correct implementation of administrative penalty provisions.

5. Adjustments

a. Identify the underlying causes for adjustments to SEEM payments.
b. Determine if the required adjustments are appropriate.
c. Validate that adjustment amounts are accurate.
d. Validate that adjustments comply with all required time frames.
e. Verify that adjustments were correctly made and completely applied.

6. Reporting

a. Validate the accuracy and completeness of data reported in SQM/SRS and PARIS reports.
b. Verify that the Tier 1 Transmitted Payment accurately reflects the PARIS calculation.
c. Verify that the Tier 2 State Payment accurately reflects the PARIS calculation.

7. Metric Change Management Process

a. Verify that BellSouth is in compliance with the PMQAP for the metric change management processes.
b. Validate compliance with established procedures for the metric change notification process.

d. Verify that changes to metrics are accurate and consistent with all SQM requirements.

d. Verify the accuracy of impact statements in metric change notification reports.

Note: Items 2 through 7 above are only applicable to the measures within the scope of the audit.

At a minimum, the audit will evaluate BellSouth's performance on the following North Carolina metrics:

Measure	Description
O-3/O-4	Percent Flow-Through Service Request Summary/Detail
O-9	Firm Order Confirmation Timeliness
P-3	Percent Missed Installation Appointments
P-4	Average Completion Interval (OCI) & Order Completion Interval Distribution
P-6/P-6C	Coordinated Customer Conversions Interval
P-8	% Provisioning Troubles within 30 Days of Service Order Completion
M&R-1	Missed Repair Appointments
M&R-2	Customer Trouble Report Rate
M&R-3	Maintenance Average Duration
M&R-4	Percent Repeat Troubles within 30 Days
M&R-5	Out of Service (OOS) > 24 Hours
B-1	Invoice Accuracy.

The auditor(s) will determine the specific months to be audited for each audit area and will use current (2004) data to complete statistical evaluations and testing of BellSouth's SQM performance measurements and SEEM payments. The auditor(s) must audit at least two months of data for each selected metric within a given audit area. The Commission may, at its discretion, ask the auditor(s) to audit additional metrics or additional timeframes as deemed necessary.

For the SEEM audit, statistical and testing methods should include validation of data in accordance with the methods and formulas provided in Appendices C, D, and E of BellSouth's North Carolina SEEM Administrative Plan, Version 1.0, dated August 1, 2003. For items 3, 4 and 6 above, the materiality criteria for exceptions are those listed in the Reposting Policy. Staff and the selected auditor will jointly determine materiality criteria for other items.

II. CONDUCT OF THE AUDIT

BellSouth and the CLP Coalition will jointly select an auditor or auditors to carry out the North Carolina SQM/SEEM audit and provide this information to the Commission within the prescribed deadline. If BellSouth and the CLP Coalition advise the Commission that they cannot agree on the choice of auditor(s), the Commission will either select the auditor(s) or establish a procedure for BellSouth to follow in order to select the auditor(s). The auditor(s) so selected will be subject to Commission approval. Subject to an appropriate protective agreement/order or other measures designed to protect the disclosure of proprietary information, BellSouth will file copies of any agreement(s) reached between it and the auditor(s) in connection with the North Carolina audit, and will promptly advise the Commission of any proposed amendments to the agreement(s) and secure Commission approval of those changes.

In the event the Commission requires the submission of bids from potential auditors, BellSouth will draft a comprehensive Request for Proposal (RFP) incorporating this document, and submit the RFP for Commission approval prior to soliciting bids. BellSouth will issue the RFPs, analyze the responses, and provide the Commission with copies of those responses and with its specific recommendations concerning auditor selection. The Commission will then select the auditor(s) to conduct the audit.

At least two weeks prior to commencing the audit, the auditor(s) will make a presentation to the Commission staff, Public Staff, BellSouth, and CLP Coalition to outline the procedures it will follow in conducting the audit, to answer questions, and to propose specific time frames for the audit. During the course of the audit, the auditor(s) will file detailed progress reports with the Chief Clerk, Commission staff, Public Staff, BellSouth, and CLP Coalition every 30 days until the audit is completed.

At the conclusion of the audit, the auditor(s) will prepare and provide to the Chief Clerk, Commission staff, Public Staff, BellSouth, and CLP Coalition a final report detailing the specific findings and conclusions from the audit, and identifying any exceptions noted during the audit. The report will present recommendations for expeditiously resolving these exceptions. BellSouth will continue to pursue the resolution of any material exceptions that remain open or unresolved, after the audit has been completed and the final report released. Within thirty (30) days of the date that the auditor releases the final report, BellSouth will agree to prepare a comprehensive action plan for resolving any material exceptions that remain open after the release of the auditor's final report. Such action plan will require the Commission's explicit approval and will include, for each material open exception, a detailed description of the actions required and a timeline within which to resolve each exception. BellSouth agrees to file the action plan, in its entirety, in the North Carolina Performance Measures docket (P-100, Sub 133k).

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 CONCERNING
	)	JOINT MOTION TO
	)	APPROVE NEW
	)	PERFORMANCE
	)	MEASUREMENT PLAN
	)	FOR BELLSOUTH

BY THE COMMISSION: On September 30, 2005, BellSouth Telecommunications, Inc. (BellSouth), and AT&T Communications of the South Central 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 will supersede and replace the current SQM/SEEM Plan. BellSouth and the CLEC Coalition also noted that on December 30, 2004, BellSouth filed a petition requesting the establishment of a new SQM/SEEM Plan; the proposed SQM/SEEM Plan in this instant case is a modified version of the SQM/SEEM Plan that BellSouth filed along with its December 2004 petition.

BellSouth and the CLEC Coalition noted that the proposed SQM/SEEM Plan has been approved and implemented in Tennessee, Georgia, and Kentucky and final approval is expected in Florida in the near future. BellSouth and the CLEC Coalition also noted that joint filings seeking approval of the proposed SQM/SEEM Plan recently have been made in Alabama, Mississippi, and South Carolina.

BellSouth and the CLEC Coalition maintained that they are seeking to have the proposed SQM/SEEM Plan approved throughout BellSouth's region. Accordingly, BellSouth and the CLEC Coalition stated, the Joint Motion is conditioned upon Commission approval of the proposed SQM/SEEM Plan without a hearing. BellSouth and the CLEC Coalition maintained that if any objection to Commission approval of the proposed SQM/SEEM Plan results in undue delay or a hearing, BellSouth and the CLEC Coalition reserve all rights they may have, including the right to propose further revisions to the proposed SQM/SEEM Plan.

The Commission concludes that good cause exists to grant the Joint Motion, thereby approving the proposed SQM/SEEM Plan, unless objections to the proposed SQM/SEEM Plan are filed by no later than Monday, November 7, 2005.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of October, 2005

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp102405.01

DOCKET NO. P-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Rulemaking, to Revise Billing and Collection Procedures for Telecommunications Companies Regarding Local Disconnection and Toll Denial	)	ORDER GRANTING MOTION AND AMENDING RULE

BY THE COMMISSION: On February 7, 2005, Carolina Telephone and Telegraph Company, Central Telephone Company, and Sprint Communications Company, L.P. (collectively, Sprint), ALLTEL Communications, Inc., the Alliance of North Carolina Independent Telephone Companies[1], and Verizon South, Inc. (collectively, the Parties) filed a Joint Motion to Amend Commission Rule R12-17(c)(1).

On February 11, 2005, the Commission issued an Order allowing interested parties to file comments on or before March 14, 2005, and reply comments by March 28, 2005. Only the Public Staff filed comments, and the Public Staff did not object to the Motion.

On March 28, 2005, the Parties filed reply comments that included proposed language requested by the Attorney General to which the Parties and Public Staff did not object.

After careful consideration, the Commission concludes that it is appropriate to grant the Motion to Amend Commission Rule R12-17(c)(1). Therefore, in view of the fact that Rule R12-17(c)(2) has previously been deleted, Rule R12-17(c)(1) should be renumbered as Rule R12-17(c) and re-written to read as follows:

> (c) Partial payments to telephone utilities. Partial payments to local service providers will be allocated as follows: first to local service, second to other regulated service, and third to nonregulated service. In the event a customer or an agent of a customer makes a payment that is within $1.00 of the past due amount and in the absence of the customer's or agent's specific instruction to apply the payment otherwise, the payment may be allocated as follows: first to past due local service, second to other past due regulated service, and third to past due nonregulated service.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

tk041105.03

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[1] Citizens Telephone Company, Concord Telephone Company, Ellerbe Telephone Company, LEXCOM Telephone Company, MEBTEL Communications, North State Communications, and Randolph Telephone Company.

DOCKET NO. P-100, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Notification of Customers Regarding	)	ORDER TO AMEND BILL INSERT AND
the Avoidance of Telephone	)	INFORMATION TO BE PRINTED IN
Solicitations	)	TELEPHONE DIRECTORIES REGARDING
	)	DO-NOT-CALL

BY THE CHAIR: On January 5, 2005, the Attorney General and the Public Staff, pursuant to G.S. 62-54 and 75-102(m), filed a Motion to Amend Bill Insert and Information to be Printed in Telephone Directories regarding the Do-Not-Call law. The Attorney General and Public Staff stated that these changes were necessary due to amendment to the federal Do-Not-Call regulations [69 C.F.R. 16368 (March 29, 2004)]. The changes to the bill insert would apply to all bill inserts to be distributed in the future. Likewise, the amended information in the telephone directories would be applicable to all telephone directories printed in the future.

WHEREUPON, the Chair reaches the following

CONCLUSIONS

After careful consideration, the Chair concludes that good cause exists to require each local exchange company and each competing local provider certified to do business in North Carolina, on a prospective basis, (1) to enclose the bill insert attached as Exhibit A, at least annually, in at least one telephone bill inserted to every residential customer; and (2) print the information attached as Exhibit B in their telephone directories.

These requirements will be deemed effective on January 28, 2005, unless substantial protests are received.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of January, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb010605.02

EXHIBIT A

UNWANTED TELEMARKETING CALLS

About The Do Not Call Registry
The Do Not Call Registry is a list of residential and cellular telephone numbers that telemarketers may not call, except in limited circumstances. The Registry is operated by the Federal Trade Commission (FTC) and enforced by North Carolina Attorney General Roy Cooper, the Federal Communications Commission (FCC) and the FTC. Placing your number on the Registry will stop most, but not all, telemarketing calls. By law, exceptions to the Registry include companies with which you have had a business relationship in the past 18 months or to which you made an inquiry in the past 3 months, non-profit organizations, political organizations and polling firms. The Registry also does not apply to business-to-business calls.

If you are on the Registry and get a call from a company with which you have an established business relationship or from a nonprofit organization, or if you are not on the Registry and want a particular telemarketer to stop calling you, simply direct that telemarketer to put your phone number on its internal Do Not Call list. The telemarketer must respect your wishes.

How To Sign Up For The Do Not Call Registry
Signing up for the Registry is free and easy. To register by phone, call 1 (888) 382-1222 from the phone you wish to register. To register online, go to *www.nocallsNC.com.* You must have an active e-mail address to register through the Internet, and you will receive a confirmation e-mail as part of the registration process. Registration will be valid for 5 years, after which time you can re-register.

What To Do If Telemarketers Continue To Call You
Under North Carolina and federal law, with limited exceptions, telemarketers may not call your phone number if it has been on the Do Not Call Registry for at least 3 months. If you continue to receive calls and your number is on the Registry, file a complaint with Attorney General Roy Cooper's Consumer Protection Division. Complaint forms can be obtained online at *www.nocallsNC.com,* or by calling 1 (877) 5-NO-SCAM.

You may also enforce the law against telemarketers by filing an action in state court. You can also file a complaint with the Federal Trade Commission online at *www.donotcall.gov* or by calling 1(888) 382-1222. In addition, you may file a complaint with the Federal Communications Commission by email at *donotcall@fcc.gov,* by calling 1(888) CALL-FCC, or by writing to Federal Communications Commission, Consumer & Governmental Affairs Bureau, Consumer Inquiries and Complaints Division, 445 12th Street, SW, Washington, DC 20554.

Other Telemarketing Protections
North Carolina and federal law provide other important protections against abusive and disruptive telemarketing calls. This is what the law says:

- At the beginning of each call, the telemarketer must clearly identify himself and the business or entity that he represents.
- At your request, the telemarketer must provide you with a telephone number or address where you can reach him.

- You may request to have your name removed from the telemarketer's calling list, and the telemarketer must take all necessary steps to remove your name and telephone number from the list.
- No telemarketer may call your home after 9 PM or before 8 AM.
- Telemarketers may not use prerecorded messages with few limited exceptions.
- Telemarketers must transmit their telephone numbers, and if possible, their names, through your caller ID service.
- Telemarketers must connect you to a sales representative two seconds after you answer the phone to eliminate annoying "dead air" calls.

Rules Applying To Telemarketing Calls Placed to Your Business

The FCC has rules in place to help business customers with telemarketing calls. The FCC's rules prohibit:

- the use of autodialers in a way that would tie up two or more lines of any business that has multiple lines. The rules require that any calls made with an autodialer must release your telephone line within five seconds of your hanging up.
- the transmission of unsolicited advertisements to fax machines. The FCC requires that the first page of each fax or each page of the message must clearly mark: (a) the date and time the transmission is sent; (b) the identity of the sender; and (c) the telephone number of the sender or of the sending fax machine. No person may transmit advertisements to your fax machine without your prior express permission or invitation, unless you have a business relationship with the transmitter of the fax. This rule applies to residential and business fax machines.

For More Information

To learn more about your rights under our telemarketing laws or how to avoid telemarketing fraud, go to www.nocallsNC.com or call Attorney General Roy Cooper's Consumer Protection Division at 1 (877) 5-NO-SCAM.

EXHIBIT B

DO NOT CALL

Residential customers who wish to reduce the number of telemarketing calls they receive may add their telephone numbers to the national Do Not Call Registry. After three months, customers on the Registry should experience a reduction in unwanted calls. To register your home or mobile phone number for free, call 1-888-382-1222 from the phone you wish to register. For more information, to register by the Internet, or to file a complaint with Attorney General Roy Cooper, go to www.nocallsnc.com or call 1-877-5-NOSCAM (566-7226).

DOCKET NO. P-100, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Notification of Customers Regarding the Avoidance of Telephone Solicitations	))	ERRATA ORDER

BY THE CHAIR: On January 7, 2005, an Order to Amend Bill Insert and Information To Be Printed in Telephone Directories Regarding Do-Not-Call was issued. However, the references in the Conclusions to Exhibit A as the bill insert and Exhibit B as the information for the telephone directories was incorrect. The references should be reversed. Exhibit A refers to the information for telephone directories. Exhibit B refers to the bill insert.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of January, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb011105.01

DOCKET NO. P-100, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Notification of Customers Regarding the Avoidance of Telephone Solicitations	))	SECOND ERRATA ORDER

BY THE CHAIR: On January 7, 2005, an Order to Amend Bill Insert and Information To Be Printed in Telephone Directories Regarding Do-Not-Call was issued in this docket. This Order contained the text for a bill insert and for publication in directories regarding the Do-Not-Call program. These were supposed to incorporate certain amendments as proposed by the Attorney General and Public Staff. Though inadvertencies, the texts for bill insert and publication in directories did not in fact incorporate these amendments.

Attached are the correct texts for Bill Insert (Exhibit A) and Directory Publication (Exhibit B).

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of January, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Pb011905.01

EXHIBIT A

DO NOT CALL

Residential customers who wish to reduce the number of telemarketing calls they receive may add their telephone numbers to the national Do Not Call Registry at no cost. After one month, customers on the Registry should experience a reduction in unwanted calls. To register your home or mobile phone number, call 1-888-382-1222 from the phone you wish to register. For more information, to register by the Internet, or to file a complaint with Attorney General Roy Cooper, go to www.nocallsNC.com or call 1-877-5-NOSCAM (1-877-566-7226).

EXHIBIT B

UNWANTED TELEMARKETING CALLS

About The Do Not Call Registry
The Do Not Call Registry is a list of residential and cellular telephone numbers that telemarketers may not call, except in limited circumstances. The Registry is operated by the Federal Trade Commission (FTC) and enforced by North Carolina Attorney General Roy Cooper, the Federal Communications Commission (FCC) and the FTC. Placing your number on the Registry will stop most, but not all, telemarketing calls. By law, exceptions to the Registry include companies with which you have had a business relationship in the past 18 months or to which you made an inquiry in the past 3 months, non-profit organizations, political organizations and polling firms. The Registry also does not apply to business-to-business calls.

If you are on the Registry and get a call from a company with which you have an established business relationship or from a nonprofit organization, or if you are not on the Registry and want a particular telemarketer to stop calling you, simply direct that telemarketer to put your phone number on its internal Do Not Call list. The telemarketer must respect your wishes.

How To Sign Up For The Do Not Call Registry
Signing up for the Registry is free and easy. To register by phone, call 1 (888) 382-1222 from the phone you wish to register. To register online, go to www.nocallsNC.com. You must have an active e-mail address to register through the Internet, and you will receive a confirmation e-mail as part of the registration process. Registration will be valid for 5 years, after which time you can re-register.

What To Do If Telemarketers Continue To Call You
Under North Carolina and federal law, with limited exceptions, telemarketers may not call your phone number if it has been on the Do Not Call Registry for at least 1 month. If you continue to receive calls and your number is on the Registry, file a complaint with Attorney General Roy Cooper's Consumer Protection Division. Complaint forms can be obtained online at www.nocallsNC.com or by calling 1-877-5-NO-SCAM (1-877-566-7226).

You may also enforce the law against telemarketers by filing an action in state court. You can also file a complaint with the Federal Trade Commission online at www.donotcall.gov or by calling 1-888-382-1222. In addition, you may file a complaint with the Federal Communications Commission by email at donotcall@fcc.gov, by calling 1-888-CALL-FCC, or by writing to Federal Communications Commission, Consumer & Governmental Affairs Bureau, Consumer Inquiries and Complaints Division, 445 12 Street, SW, Washington, DC 20554.

Other Telemarketing Protections

North Carolina and federal law provide other important protections against abusive and disruptive telemarketing calls, such as:

- At the beginning of each call, the telemarketer must clearly identify himself or herself and the business or entity that he or she represents.
- At your request, the tetemarketer must provide you with a telephone number or address where you can contact the telemarketing company.
- You may request to have your name removed from the telemarketer's calling list, and the telemarketer must take all necessary steps to remove your name and telephone number from the list.
- No telemarketer may call your home after 9 PM or before 8 AM.
- Telemarketers may not use prerecorded messages with few limited exceptions.
- Telemarketers must transmit their telephone numbers, and if possible, their names, through your caller ID service.
- Telemarketers must connect you to a sales representative two seconds after you answer the phone to eliminate annoying "dead air" calls.

Rules Applying To Telemarketing Calls Placed to Your Business

The FCC has rules in place to help business customers with telemarketing calls. The FCC's rules prohibit:

- the use of autodialers in a way that would tie up two or more lines of any business that has multiple lines. The rules require that any calls made with an autodialer must release your telephone line within five seconds of your hanging up.
- the transmission of unsolicited advertisements to fax machines. The FCC requires that the first page of each fax or each page of the message must clearly mark: (a) the date and time the transmission is sent; (b) the identity of the sender; and (c) the telephone number of the sender or of the sending fax machine. No person may transmit advertisements to your fax machine without your prior express permission or invitation, unless you have a business relationship with the transmitter of the fax. This rule applies to residential and business fax machines.

For More Information

To learn more about your rights under our telemarketing laws or how to avoid telemarketing fraud, go to www.nocallsNC.com or call Attorney General Roy Cooper's Consumer Protection Division at 1-877-5-NO-SCAM (1-877-566-7226).

DOCKET NO. P-100, SUB 153

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Designation of 311 for Non-Emergency Police And Other Government Services	)))))	ORDER DESIGNATING USE OF 311 AS A NON-EMERGENCY AND OTHER GOVERNMENT SERVICES NUMBER AND GRANTING PETITION

BY THE COMMISSION: On June 30, 2003, the City of Charlotte (the City), the Charlotte-Mecklenburg Police Department (CMPD), and the County of Mecklenburg (the County) (jointly hereinafter Petitioners) filed a Petition requesting the Commission to designate the 311 abbreviated dialing code for use as a non-emergency police and other government services number for the City of Charlotte and the County of Mecklenburg.

On April 12, 2005, the Petitioners made a Supplemental Filing in support of their June 30, 2003 Petition. In the Supplemental Filing, the Petitioners provided responses to questions posed by the Public Staff of the North Carolina Utilities Commission and filed an Executive Summary of the information developed by the City-County 311 Implementation Team.

On April 21, 2005, the Chair issued an *Order Requesting Initial and Reply Comments* on the Petitioners' June 30, 2003 Petition and April 12, 2005 Supplemental Filing.

On May 5, 2005, BellSouth Telecommunications, Inc. (BellSouth) and the Public Staff filed initial comments. On May 19, 2005, Verizon South Inc. (Verizon) filed reply comments.

JUNE 30, 2003 PETITION

The Petitioners filed a Petition to request the Commission to designate the 311 abbreviated dialing code for use as a non-emergency police and other government services number for the City of Charlotte and the County of Mecklenburg.

The Petitioners noted that in 1997 the Federal Communications Commission (FCC) released its *First Report and Order and Further Notice of Proposed Rulemaking (First Report and Order)*[1] in which it assigned 311 as an abbreviated dialing code on a nationwide basis. The Petitioners noted that the FCC stated that 911 centers receive a large percentage of inappropriate calls and, in response, designated the 311 code for non-emergency police services and other governmental services. The Petitioners maintained that the FCC declared that the use of 311 would improve the effectiveness of 911 emergency services by alleviating congestion on these circuits and thereby permit more effective operation of emergency services.

The Petitioners noted that the FCC's *First Report and Order* also stated that "ensuring that 911 circuits are not overburdened by non-emergency calls is also of utmost importance. Eventually, the use of a single nationwide code for non-emergency calls will let callers know that

[1] FCC 95-51, CC Docket No. 92-105, released on February 19, 1997.

they can dial this code exchange to obtain necessary governmental services without hampering others' access for emergencies." (*First Report and Order*, ¶ 36)

The Petitioners also maintained that the FCC's *First Report and Order* provided that local jurisdictions should have the discretion to determine whether 311 should be used on a local basis to reach governmental services in addition to the code's non-emergency use. The Petitioners asserted that the ability of local governments to determine the need for relief for their local 911 systems was noted as a critical factor in evaluating a local entity's request for 311 implementation.

The Petitioners noted that in a manner similar to the Department of Transportation's Request for a N11 abbreviated dialing code to support the statewide travel information system, which was granted by the Commission on April 24, 2003, the City of Charlotte and the County of Mecklenburg were submitting a request for the abbreviated dialing code of 311 for use as a non-emergency police and other government services number.

The Petitioners maintained that the designation of 311 for the City and the County would relieve the overburdened 911 emergency system operated by the City and the CMPD and facilitate citizen access to government services and information. They asserted that neither the City of Charlotte nor Mecklenburg County currently has a single access point for citizens to access government services. The Petitioners argued that the City of Charlotte/Mecklenburg County governmental telephone directory lists approximately 1,457 telephone numbers for governmental services. They noted that the City and County have more than 40 frequently called numbers covering more than 115 services. The Petitioners stated that the annual call volume for City services is approximately 994,529 while the County's call volume is 1,252,510.

The Petitioners asserted that the establishment of a 311 call center providing 24-hour a day access would allow other call centers within the City to reduce their hours of operation to standard business hours, while providing more efficient and responsive customer service to the community.

The Petitioners stated that the Metropolitan Statistical Area (MSA) of Charlotte includes Mecklenburg, Cabarrus, Gaston, Lincoln, Rowan and Union Counties in North Carolina and York County in South Carolina. They noted that the total population of the metro region according to the 1990 census was 1,587,905. By contrast, the Petitioners maintained, the 2000 census reflects that same metro region to have a population of 2,004,651. The Petitioners stated that the population of the City of Charlotte for the year 2002 was approximately 579,684; the population of Mecklenburg County for the year 2002 was approximately 746,427.

Additionally, the Petitioners commented, Charlotte and Mecklenburg County have seen substantial growth as financial, distribution, and transportation centers. They noted that, during the past ten years, 8,395 new companies have invested more than $5.5 billion in new Charlotte facilities. They stated that the growth of the banking industry in Charlotte has contributed to the growth of the City and the County, which is reflected in the 220 local branches of 20 banks in Charlotte, as well as the Federal Reserve Branch. The Petitioners noted that Charlotte is the Nation's second largest banking center.

GENERAL ORDERS – TELECOMMUNICATIONS

The Petitioners noted that the CMPD currently operates an Enhanced 911 system, which serves the City of Charlotte and Mecklenburg County. They stated that the towns of Pineville, Huntersville, and Cornelius, which are located within Mecklenburg County, operate their own 911 systems. The Petitioners asserted that the Enhanced 911 system receives calls for police, fire, and medic services and is responsible for transferring fire and medic calls to the appropriate agency.

The Petitioners stated that there are approximately 550,000 wireline telephone lines in the Charlotte-Mecklenburg area.. They asserted that further complicating the telecommunications situation in Charlotte and Mecklenburg County was the recent addition of a second area code of 980 into the existing 704 area code. The Petitioners argued that due to the profusion of cellular phones, faxes, and modems within the rapidly growing Charlotte area, BellSouth recently converted to a 10-digit dialing procedure for all local calls. Consequently, they maintained, access to governmental services is now encumbered by the need to dial the area code when attempting to obtain services or information. The Petitioners stated that, with the advent of ten-digit dialing, the need for an abbreviated code for non-emergency police services and governmental services is even more urgent.

The Petitioners asserted that the CMPD has designated a separate unit to handle non-emergency matters on a walk-in and call-in basis. They noted that the Non-Emergency Police Services Unit (NEPS) takes reports from citizens who come into the Department on a walk-in basis and is responsible for calls forwarded from an auto attendant, in addition to handling calls from within the police department. Additionally, the Petitioners stated, the 911 Communications Center transfers non-emergency telephone calls to this unit.

The Petitioners maintained that the NEPS unit is staffed by 26 non-sworn personnel with approximately six of those on duty at any given time. They noted that approximately nine sworn law enforcement officers are also assigned to NEPS. The Petitioners asserted that the NEPS unit operates from 7:00 am to 11:00 pm seven days a week. The Petitioners commented that the NEPS unit's additional responsibilities include a report writing function, which entails making appropriate entries into the Knowledge Based Community Oriented Police System (KBCOPS) computer system; police officers may also be dispatched as a result of a call to NEPS.

The Petitioners stated that the NEPS unit handled approximately 237,737 calls for service during 2002. In addition, they noted, NEPS personnel completed police reports for 31,262 of these calls. The Petitioners maintained that the average time involved for a call involving the initiation of a police report was approximately 27 minutes. The Petitioners stated that the NEPS unit also assists individuals who walk into the police department requesting assistance. In 2002, the Petitioners commented, the unit assisted approximately 4,188 citizens on a walk-in basis.

The Petitioners maintained that a 311 feasibility analysis, conducted by PSLC, L.L.C., in 1999, noted an average call abandonment rate of 16% for all the 21 Charlotte-Mecklenburg government call centers. They stated that the NEPS unit, however, showed a 22% call abandonment rate and for the year 2002 showed an abandonment rate of 37.5%. The Petitioners stated that an appropriate goal, according to the feasibility study, would be an abandonment rate of 5% to 10%.

The Petitioners noted that during the fiscal year (FY) 2001-2002, CMPD received approximately 1,029,884 calls to its 911 communications center. They stated that this compares with 456,000 calls to the 911 communications center in calendar year 1996. The Petitioners maintained that wireless calls to the 911 communications center comprise approximately 46% of the total calls; the 911 Center dispatched approximately 690,096 calls for service in the FY 2001-2002.

The Petitioners asserted that the public interest of the citizens of the City and the County would be served by the implementation of 311 as a non-emergency police and other governmental services dialing code. Currently, they noted, no jurisdiction in North Carolina has requested the implementation of 311 as a non-emergency dialing code. The Petitioners noted that the United Way currently operates 211 in Mecklenburg County as a program of the United Way of Central Carolinas; United Way 211 Referral Specialists are on duty 24 hours a day and provide persons in need with information about community resources available within the area.

The Petitioners maintained that a recent example reflecting the overwhelming need for relief for 911 was the severe ice storm that struck Charlotte and Mecklenburg County on December 4, 2002. They stated that the ice storm caused major power outages in the region and placed significant burdens on city and county services. The Petitioners asserted that the 911 communications center would ordinarily receive an average of 2,500 calls for that particular day of the week, but on the day of the ice storm, the center received approximately 8,600 calls. The Petitioners noted that many of the calls received by the 911 center were non-emergency calls ranging from questions about road conditions to school closings. The Petitioners argued that an alternative number such as 311 would have significantly relieved the 911 center to focus on actual emergency situations.

Additionally, the Petitioners noted, representatives from both the City and the County have worked closely over the past several months with representatives from BellSouth, the largest telecommunications provider in the area. They stated that BellSouth has indicated its support of this proposal.

The Petitioners commented that the FCC's *First Report and Order* notes that the current use of 911 as a national uniform N11 code of emergency services serves the public interest and is known throughout the country as a code for obtaining emergency assistance; therefore, the FCC in its Order sought to preserve the status of the 911 dialing code.

The Petitioners argued that North Carolina General Statute 62A-2, the Public Safety Telephone Act, sets forth the following Legislative purposes:

> The General Assembly declares it has to be in the public interest to provide a toll free number through which an individual in this State can gain rapid, direct access to public safety aid. The number shall be provided with the objective of reducing response time to situations requiring law enforcement, fire, medical, rescue, or other public safety service.

They asserted that the implementation of 311 promotes this legislative intent by providing to the public an abbreviated number for non-emergency services and other governmental services, while simultaneously alleviating the enormous burden on the 911 communications center. The

Petitioners argued that, by preserving the 911 dialing code for actual emergencies, those citizens will receive the rapid, direct access to public safety aid intended by the legislature. They stated that those citizens in need of non-emergency police services or other governmental assistance or guidance will likewise receive prompter and more efficient information from a 311 call center than a mistakenly directed call to 911.

In summary, the Petitioners argued that the rapid growth of the Charlotte-Mecklenburg region and the resulting strain placed on the 911 emergency system, necessitate the addition of the 311 abbreviated code for non-emergency police services and other governmental services. Accordingly, the City of Charlotte, the CMPD, and the County of Mecklenburg, respectfully, requested that the Commission assign the 311 abbreviated code to the area in accordance with the dictates of the FCC's Order.

APRIL 12, 2005 SUPPLEMENTAL FILING

The Petitioners stated that in response to the filing of the original Petition on June 30, 2003, the Public Staff informally posed several questions to the Petitioners. The Petitioners noted that, in the ensuing time period, the Petitioners have endeavored to address those questions. Additionally, the Petitioners included an Executive Summary containing additional information concerning the relief requested in the Petition.

The following represents questions from the Public Staff and the responses provided by the Petitioners:

Q. **Has Charlotte/Mecklenburg sponsored a workshop to allow telecommunications service providers (e.g., wireline, wireless, payphones, etc.) and other interested parties an opportunity to discuss your proposed use of the 311 code? If so, what were the results of the workshop?**

A. The City of Charlotte, in conjunction with Mecklenburg County, sponsored a workshop for wireless and wireline service providers on February 10, 2005 to explain the 311 proposal as well as to solicit their comments and concerns. Each provider was asked to indicate the impact of the 311 Non-Emergency calling on their operations including:

- A timeline to implement 311 calling access;
- Itemized costs for providing 311 calling access;
- Identification of any issues associated with making 311 available throughout the City of Charlotte and Mecklenburg County.

As a follow-up to the Workshop, informational packets were sent via certified mail to over 80 providers requesting their input and comments on the issues listed above. These packets included the City and County's target date of July 2005 for implementation of the 311 Call Center. The Workshop and follow-up mailings resulted in responses to date from 30 providers. The specific comments submitted by the wireline and wireless Providers were incorporated into a database for future reference. The Petitioners noted that a complete database is available for the Commission's review if required.

A summary of the Provider's comments and the Implementation Team's response is set forth below:

- Most wireline providers indicated that BellSouth was primarily responsible for managing the switching and translation for the implementation of 311.
- BellSouth, the primary Incumbent Local Exchange Carrier, has worked with the 311 Implementation Team to insure that the translation equipment and protocol for carriers and providers with operations in Mecklenburg County is operational.
- Wireless providers have not indicated any concerns with the 311 proposal. The concerns that were expressed involve cell towers that may provide service to residents outside of Mecklenburg County.
- Understanding this concern, the 311 Implementation Team is contacting surrounding counties to secure referral and handling information.

Q. Have other local governments, state or non-state agencies in the proposed implementation area been contacted about or expressed an interest in this proceeding, to Charlotte/Mecklenburg's knowledge?

A. The City of Charlotte, in conjunction with Mecklenburg County, sponsored a workshop for officials from the various Mecklenburg County municipalities on January 11, 2005 to gain their input and support for the proposed use of 311. The municipalities participating included: Cornelius, Davidson, Huntersville, Matthews, Mint Hill, and Pineville. The specific comments submitted by the municipalities were incorporated into a database for future reference. The Petitioners noted that a complete database is available for the Commission's review if required. A summary of their comments and the 311 Implementation Team's response is as follows:

- All municipalities are providing referral phone numbers and departmental contacts for use by representatives in the 311 Call Center.
- Comments and referral information provided by the municipalities will be placed into a database and incorporated into the 311 Call Center's computerized information database.
- The 311 Call Center will forward calls for the six municipalities to the appropriate numbers which were provided by those municipalities.
- The concerns of municipalities whose areas of influence may include counties outside of Mecklenburg were the following:
    - Telephone exchanges that may cross jurisdictional boundaries.
    - Addresses that involve telephone exchanges from one jurisdiction and geographical inclusion in another jurisdiction.

- These concerns will be handled by providing 311 Customer Service Representatives with desktop access to the City-County Geographic Information Systems (GIS) Virtual Map Book which will enable verification of municipal locations by street address.
- The six municipalities within Mecklenburg County have indicated an interest in participating in the 311 Non-Emergency Call center and future phases will attempt to incorporate them into the project.

- The 311 Implementation Team is in the process of contacting the counties surrounding Mecklenburg to secure referral and contact information for calls addressing issues within their respective counties.

Q. Has Charlotte/Mecklenburg determined how many centers will be answering the calls? Will selective routing and associated databases be needed?

A.

- The City of Charlotte and Mecklenburg County will have only one primary 311 Non-Emergency Call Center.
- Selective routing will not be utilized in this proposal.

Q. Is it Charlotte/Mecklenburg's intent that the 311 code be translated by all wireline and wireless carriers to an 800 number, or will the "translated to" number depend upon the "calling from" location? If an 800 number will not be used, is there a ten-digit number that is local to all areas in which Charlotte/Mecklenburg wants the code available?

A. An 800 number will not be required. The number for translating all 311 calls generated in the City of Charlotte or Mecklenburg County will be 704-336-2040. A technical diagram detailing the 311 Implementation is attached.

Q. Does Charlotte/Mecklenburg intend that 311 access be available from callers located outside of the county? Outside the state?

A. Currently, there are no plans to provide 311 access from wireless or wireline callers outside of Mecklenburg County or outside of North Carolina.

311 Team members are meeting with adjacent counties in both North and South Carolina to discuss issues and evaluate potential interest.

Q. Will Charlotte/Mecklenburg be responsible for charges made by the carriers for recovery of translation costs and other facility costs of the service?

A. The City of Charlotte has indicated a willingness to assist providers in recovering extraordinary costs associated with modifications to translation and routing facilities. Since costs of implementation will be absorbed by the project, the 311 Team is currently negotiating with some wireless carriers who have submitted implementation cost estimates ranging between $1,100 and $8,600.

In conclusion, the Petitioners requested that the Commission grant the use of the 311 abbreviated dialing code for non-emergency and other governmental services to the City of Charlotte and Mecklenburg County.

INITIAL COMMENTS

BELLSOUTH: BellSouth stated that it supports the implementation of the 311 abbreviated dialing code for use as a North Carolina non-emergency police and other government services number for the City of Charlotte and the County of Mecklenburg, as long as BellSouth is allowed to recover its reasonable costs associated with implementing the code.

BellSouth noted that, as with the implementation of the 211 and 511 dialing codes allowed by the Commission, all service providers should be permitted to make the 311 service available by a tariff, on a central office basis, throughout the County of Mecklenburg.

BellSouth maintained that the Local Calling Area of the 311 service subscribers will be the Local Calling Area as defined in Section A3.5 of BellSouth's General Subscriber Services Tariff.

BellSouth stated that it will provide 311 service in BellSouth's territory only. BellSouth maintained that to provide access to a 311 number to end users in an independent company territory or to end users of competing local providers (CLPs) within the local service area, the 311 subscriber must make the appropriate arrangements with the independent company or CLP.

BellSouth attached a proprietary cost study that reflects the costs associated with the implementation of 311 service that BellSouth would seek to recover if the 311 code is allowed by the Commission.

BellSouth noted that, should the Commission order implementation of the 311 service, BellSouth would ask that it and other service providers be given appropriate time to file tariffs and implement the service. BellSouth stated that in order to facilitate and accommodate the desired implementation date of June 1, 2005 as requested by the City of Charlotte, BellSouth is requesting a decision from the Commission prior to that time.

PUBLIC STAFF: The Public Staff noted that in FCC 97-51, CC Docket No. 92-105, released on February 19, 1997, the FCC found the assignment of 311 as a national number through which the public could gain access quickly to non-emergency police and other government services to be in the public interest. The Public Staff stated that the FCC also required that within six months of receipt of a request from an entity (for example, a local police or fire chief) to use 311 for such purposes in a particular jurisdiction, a telecommunications service provider should: (1) ensure that entities assigned 311 at the local level prior to the effective date of the Order relinquish non-compliant uses; and (2) take any steps necessary to complete 311 calls from its subscribers to a requesting 311 entity in its service area. The Public Staff stated that it is not aware of any non-compliant uses of the 311 code in North Carolina.

The Public Staff maintained that, in the Petitioners' Supplemental Filing, they demonstrated that they have completed many of the steps necessary for implementation of the service. The Public Staff commented that the Petitioners have already met with the telecommunications services providers obligated through the FCC Order to make the needed changes to accommodate their request. The Public Staff stated that the Petitioners have also met with other local government entities in the area on the subject of misdirected calls and are prepared to transfer calls or refer callers to the appropriate numbers as agreed by the parties.

The Public Staff noted that the Petitioners state that they anticipate using a single local number as the "translate to" number for the 311 code.

The Public Staff also noted that the Petitioners indicate a willingness to assist providers in recovering extraordinary costs associated with modifications to translation and routing facilities. The Public Staff stated that the 311 Implementation Team is negotiating with some wireless carriers who have submitted implementation costs. The Public Staff maintained that the Petitioners recognize that there may be charges by the local exchange companies that will participate in provision of the service.

The Public Staff recommended that the Commission grant the Petition by designating the use of the 311 code as requested and directing that each telecommunications service provider under the Commission's jurisdiction that has been requested to accommodate the Petitioners' use of the code do so on a timely basis. The Public Staff further recommended that any charges for regulated services performed by the local exchange companies to accommodate the request should be filed with the Commission, as described below.

The Public Staff stated that there are relatively minor differences between the Petitioners' proposal, the United Way's proposal for the use of 211, and the Department of Transportation's use of 511 that may impact the charges for the services, but the costs involved in implementing the services on a per office basis should be very similar. The Public Staff noted that rates for implementation of 511 were filed in 2004 and reflected updated costs relative to those in place for 211.

For ease of administration, the Public Staff recommended that the companies that have filed charges for implementation of 211 or 511 utilize those same charges for the nonrecurring charges (NRCs) applicable to 311 service. The Public Staff further recommended that the Commission find that, if there has been a significant increase in loaded labor rates since the previous charges were filed, revised charges may be necessary. The Public Staff proposed that the Commission find that, if the companies anticipate a lower number of hours per office to be involved in the 311 translations, the proposed charges should reflect a reduction in required hours. The Public Staff also proposed that the Commission conclude that those companies that have not filed charges for 211 implementation should establish NRCs similar to those filed previously by other companies for 211 implementation. The Public Staff recommended that the Commission order the companies to file tariffs as needed under the standard notice interval with the Commission to accommodate the local governments' requests; companies not involved in the Petitioners' project need not file tariffs until a request for their services is made.

The Public Staff noted that the Petitioners are the first local government entities to request Commission authority to use the 311 code pursuant to the FCC Order. The Public Staff commented that there are a large number of local government entities that could make similar requests. The Public Staff opined that, rather than address each case as it arises, the Commission should concur with the FCC's designation of the use of the 311 code throughout North Carolina and direct all regulated telecommunications service providers to accommodate any local government's request that is consistent with the use of the code as authorized by the FCC. The Public Staff stated that consideration of this statewide action should not, however, delay the Commission's timely designation of the use of the 311 code as requested by Petitioners.

REPLY COMMENTS

VERIZON: Verizon responded in reply comments to the initial comments filed by BellSouth and the Public Staff.

Verizon stated that it agrees with BellSouth's recommendation that 311 service providers be allowed to recover the cost of providing such services. Verizon asserted that it is critical in a competitive market environment that prices reflect underlying costs. Verizon opined that setting rates for 311 service below cost would shift the burden of cost recovery from the 311 governmental agency to the general body of ratepayers who may not use 311. Verizon asserted that this puts the 311 service provider at a competitive disadvantage because the 311 provider must set the prices of its other products to provide support for the 311 service. However, Verizon maintained, the result of pricing products to support below-cost service cannot be sustained in a competitive market.

Verizon disagreed with Public Staff's recommendation that rates intended to capture the NRCs of implementing 211 or 511 services be utilized for 311 services. Verizon stated that its 211 service rates are based on cost studies filed in March 2000, and thus would not accurately capture the cost of the AIN platform that would be used to provision 311 services. Verizon noted that, while its 511 service rates are based on an AIN cost study submitted in April 2004, these rates were developed specifically for the North Carolina Department of Transportation (NCDOT), reflecting only the features and functionalities ordered by the NCDOT, and therefore would understate the cost of provisioning 311 services. In the spirit of compromise, however, Verizon stated that it would be willing to use the tariffed 511 NRC rates for 311 services on an ***interim*** basis, provided the Commission opens a proceeding to determine permanent rates for 311 services based on new cost studies.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that good cause exists to grant the Petitioners' June 30, 2003 Petition by designating the use of the 311 code as requested and directing that each telecommunications service provider under the Commission's jurisdiction that has been requested to accommodate the Petitioners' use of the code do so on a timely basis. The Commission further finds it appropriate to conclude that any charges for regulated services performed by the local exchange companies to accommodate the request should be filed with the Commission, as described below.

The Commission concludes that, on an interim basis, the companies that have filed charges for implementation of 211 or 511 should utilize those same charges for the NRCs applicable to 311 service. The Commission will open a proceeding to determine permanent rates for 311 services based on new cost studies. If the Commission finds that there has been a significant increase in loaded labor rates since the previous charges were filed, revised charges may be necessary. If the companies anticipate a lower number of hours per office to be involved in the 311 translations, the proposed charges should reflect a reduction in required hours.

The Commission further concludes that those companies that have not filed charges for 211 implementation should establish NRCs similar to those filed previously by other companies for 211 implementation. The companies shall file tariffs as needed under the standard notice interval with the Commission to accommodate the local governments' requests; companies not involved in Petitioners' project need not file tariffs until a request for their services is made.

The Commission notes that the Petitioners are the first local government entities to request Commission authority to use the 311 code pursuant to the FCC Order. The Commission agrees with the Public Staff that there are a large number of local government entities that could make similar requests. Therefore, the Commission finds it appropriate to concur with the FCC's designation of the use of the 311 code throughout North Carolina and hereby directs all regulated telecommunications service providers to accommodate any local government's request that is consistent with the use of the code as authorized by the FCC.

IT IS, THEREFORE, ORDERED as follows:

1. That the Petitioners' June 30, 2003 Petition is granted; thereby, the use of the 311 abbreviated dialing code for non-emergency and other governmental services to the City of Charlotte and the County of Mecklenburg is hereby approved.

2. That the Commission concurs with the FCC's designation of the use of 311 throughout North Carolina and directs all regulated telecommunications service providers to accommodate any local government's request that is consistent with the use of the code as authorized by the FCC.

3. That, on an interim basis, the companies that have filed charges for implementation of 211 or 511 should utilize those same charges for the NRCs applicable to 311 service.

4. That, by further order, the Commission will open a proceeding to determine permanent rates for 311 services based on new cost studies.

5. That those companies that have not filed charges for 211 implementation should establish NRCs similar to those filed previously by other companies for 211 implementation.

6. That the companies shall file tariffs as needed under the standard notice interval with the Commission to accommodate the local governments' requests; companies not involved in the Petitioners' project need not file tariffs until a request for their services is made.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of May, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp052605.01

DOCKET NO. WR-100, SUB 5

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for Rulemaking to Implement North Carolina Session Law 2004-143 (House Bill 1083)	))	ORDER ADOPTING RULES

BY THE COMMISSION: On July 29, 2004, North Carolina Session Law 2004-143 (House Bill 1083) was signed into law. The legislation provided that it would become effective on August 1, 2004. In addition to changes to the General Statutes, Commission Rules R18-11 through R18-17 would be rescinded and Commission Rules R18-1 through R18-7, as they existed on December 18, 2001, would be reinstated.

The Commission found that, although the former rules (Rules R18-1 through R18-7) were better suited for operating in accordance with the new legislation than the then current rules (Rules R18-11 through R18-17), the former rules need some revision in order to properly implement the new legislation. Whereupon, the Commission initiated a rulemaking proceeding to implement North Carolina Session Law 2004-143 and issued an Order Initiating Rulemaking Procedure on August 2, 2004. Said Order adopted interim rule and solicited comments from interested parties.

On August 20, 2004, the Attorney General's Office (AG) and the North Carolina Justice and Community Development Center (JC) filed comments regarding the matter. The AG and JC recommended that an additional sentence be added to proposed Rule R18-5(a).

On August 23, 2004, the Public Staff (PS) filed comments regarding the proposed rules. The Public Staff had discussed the proposed rules with the Apartment Association of North Carolina (AANC) and the comments and recommendations of the PS are the joint comments and recommendations of the PS and AANC. In addition to agreeing with the recommendations of the AG & JC, the PS recommended changes to Rule R18-6 to allow a provider to recover base charges paid to their suppliers through the administrative charge. The recommended change allows a provider to request an administrative fee greater than $3.75 (a maximum of $3.75 is allowed for the provider to recover its cost of meter reading, billing, and collecting) upon a proper showing of the expenses incurred.

The PS also recommended that, in order to allow sufficient time to review the allocation of the supplier's base charge among the provider's tenants, the request for an administrative charge greater than $3.75 be automatically suspended for a period of 30 days after filing. General Statute 62-110(g)(7) provides that a "notification of revised schedule of rates and fees shall be presumed valid and shall be allowed to become effective upon 14 days notice to the Commission, unless otherwise suspended or disapproved by order issued within 14 days after filing." The Statute requires that suspension of an application be done by Commission Order, therefore the Public Staff is requested to recommend to the Commission (prior to the expiration of 14 days after filing of an application) whether to approve, disapprove, or suspend the application.

Based upon the recommendations of the parties and the experience gained in operating under the interim rules since August 2, 2004, the Commission is of the opinion that good cause exists to incorporate the recommendations of the Attorney General's Office, the North Carolina Justice and Community Development Center, the Public Staff, and the Apartment Association of North Carolina, into the proposed rules and adopt said rules as Commission Rules R18-1 through R18-7.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rules R18-1 through R18-7 (attached as Appendix A) are hereby promulgated and shall supersede the existing interim rules. The Commission will issue an Order adopting revised application forms to incorporate these revised rules.

2. That the Public Staff is requested to recommend to the Commission (prior to the expiration of 14 days after filing of an application) whether to approve, disapprove, or suspend the application.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of January, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rb121404.01

APPENDIX A

Chapter 18.

Provision of Water and Sewer Service by Landlords.

Rule R18-1. Application.

This Chapter governs charging for the costs of providing water or sewer utility service as authorized by G.S. 62-110(g).

Rule R18-2. Definitions.

(a) *Same contiguous premises.* An apartment complex or manufactured home park located on property that is not separated by property owned by others. Property will be considered contiguous even if intersected by a public thoroughfare if, absent the thoroughfare, the property would be contiguous.

(b) *Provider.* The landlord purchasing water or sewer utility service from a supplier and charging for the costs of providing the service or services to tenants. The provider shall be the owner of the premises served.

(c) *Supplier.* A public utility or an agency or organization exempted from regulation from which a provider purchases water or sewer service.

(d) *Tenant.* The lessee of property from the landlord, to whom the water or sewer service purchased by the provider from the supplier is provided.

(e) *Apartment complex.* Premises where one or more buildings under common ownership comprising fifteen (15) or more apartments are available for rental to tenants.

(f) *Manufactured home park.* Premises where a combination of fifteen (15) or more manufactured homes, as defined in G.S. 143-145(7), or spaces for manufactured homes, are rented to or are available for rental to tenants.

(g) *Supplier's base charge.* The fixed charge imposed by the supplier for providing water and sewer utility service to the provider. This charge may include charges related to the provision of utility service such as the cost of meter reading, billing, and collecting, but may not include charges not related to the provision of utility service, such as stormwater fees, trash collection, or property taxes.

Rule R18-3. Utility status; certificate; bonds.

Every provider is a public utility as defined by G.S. 62-3(23)a.2 and shall comply with all applicable provisions of the Public Utilities Act and all applicable rules and regulations of the Commission. No provider shall begin charging for the costs of providing water or sewer service prior to applying for and receiving a certificate of authority from the Commission. No provider shall be required to post a bond pursuant to G.S. 62-110.3.

Every application for authority to charge for the costs of providing water or sewer service shall be in such form and detail as the Commission may prescribe and shall include (a) a description of the applicant and the property to be served, (b) a description of the proposed billing method and billing statements, (c) a schedule of the rates charged to the applicant by the supplier, (d) the schedule of rates the applicant proposes to charge the applicant's customers, (e) the administrative fee proposed to charged by the applicant, (f) the name of and contact information for the applicant and its agents, (g) the name of and contact information for the supplying water or sewer system, and (h) any additional information that the Commission may require. The Commission shall approve or disapprove an application within 30 days of the filing of a completed application with the Commission. If the Commission has not issued an Order disapproving a completed application within 30 days, the application shall be deemed approved.

Rule R18-4. Compliance with rules.

Every provider shall comply with any applicable rules of local governmental agencies regarding the provision of water or sewer service.

Rule R18-5. Records, reports and fees.

(a) All records shall be kept at the office or offices of the provider in North Carolina, or shall be made available at its office in North Carolina upon request, and shall be available during regular business hours for examination by the Commission or Public Staff or their duly authorized representatives. Within three business days after a written request to the provider, a customer may examine the records pertaining to the customer's account during regular business hours and may obtain a copy of those records at a reasonable cost, which shall not exceed twenty-five cents (25¢) per page.

(b) Providers shall not be required to file an annual report to the Commission as required by Chapter 1, Rule R1-32 of the Rules and Regulations of the North Carolina Utilities Commission. Providers shall pay a regulatory fee and file a regulatory fee report as required by Chapter 15, Rule R15-1. Special reports shall also be made concerning any particular matter upon request by the Commission.

Rule R18-6. Rates.

(a) The rates shall equal the cost of purchased water or sewer service (The usage rate charged by the provider shall equal the usage rate charged by the supplier.). A Commission-approved administrative fee not to exceed $3.75 may be added to the cost of purchased water and sewer service to compensate the provider for meter reading, billing, and collection. A provider whose schedule of rates and fees does not include a separate base charge to the tenant may request approval of an administrative fee greater than $3.75 to recover the base charge from its supplier. With the exception of base charges approved before August 1, 2004, all charges other than the administrative fee shall be based on tenants' metered consumption of water. All sewer service shall be measured based on the amount of water metered. Metered consumption of water shall be determined by metered measurement of all water consumed by the tenant, and not by any partial measurement of water consumption (i.e., ratio utility billing system (RUBS) and hot water capture, cold water allocation (HWCCWA) are not allowed), unless specifically authorized by the Commission.

(b) A provider of water or sewer service may track increases in the unit consumption rate charged by the supplier of such service, and may (subject to limitations imposed by Commission Rules) change its administrative fee, by filing with the Commission a notification of revised schedule of rates and fees. Every notification of revised schedule of rates and fees shall be in such form and detail as the Commission may prescribe and shall include (1) the current schedule of the unit consumption rates charged by the provider, (2) the schedule of unit consumption rates charged by the supplier to the provider that the provider proposes to pass through to the provider's customers, (3) the schedule of the unit consumption rates proposed to be charged by the provider, (4) the current administrative fee charged by the provider, and, if applicable, (5) the administrative fee proposed to be charged by the provider. Any such notification of revised schedule of rates and fees shall be presumed valid and shall be allowed to become effective simultaneously with the increase in the unit consumption rate of the supplier upon 14 days notice to the Commission, unless otherwise suspended or disapproved by Commission Order issued within 14 days after filing.

(c) Every request for approval of an administrative fee in excess of $3.75 shall include (1) the provider's cost of meter reading, billing, and collection, (2) the current or proposed base charge from the supplier, (3) the number of tenants to whom water or sewer service is provided, and (4) the proposed administrative fee. Any such request shall be suspended for a period of 30 days after filing.

(d) No provider shall charge or collect any greater or lesser compensation for the costs of providing water or sewer service than the rates approved by the Commission.

Rule R18-7. Disconnection; billing procedure; meter reading.

(a) No charge for connection or disconnection, charge for late payment, or similar charge in addition to the rate specified in Rule R18-6 shall be allowed.

(b) No provider may disconnect water or sewer service for nonpayment.

(c) Bills shall be rendered at least monthly.

(d) The date after which a bill for water or sewer utility service is due, or the past due after date, shall be disclosed on the bill and shall not be less than twenty-five (25) days after the billing date.

(e) A provider shall not bill for or attempt to collect for excess usage resulting from a plumbing malfunction or other condition which is not known to the tenant or which has been reported to the provider.

(f) Every provider shall provide to each customer at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following:

(1) A copy of the rates, rules and regulations of the provider applicable to the premises served from that office.

(2) A copy of these rules and regulations.

(3) A statement advising tenants that they should first contact the provider's office with any questions they may have regarding bills or complaints about service, and that in cases of dispute, they may contact the Commission either by calling the Public Staff - North Carolina Utilities Commission, Consumer Services Division, at (919) 733-9277 or by appearing in person or writing the Public Staff - North Carolina Utilities Commission, Consumer Services Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326.

(g) Each provider shall adopt some means of informing its tenants as to the method of reading meters. Information on bills shall be governed by Chapter 7, Rule R7-23 and Chapter 10, Rule R10-19. Additionally, the bill shall contain a toll-free phone number for contacting the provider or the agent regarding service or billing matters. Adjustment of bills for meter error shall be governed by Chapter 7, Rule R7-25. Testing of water meters shall be governed by Chapter 7, Rules R7-28 through R7-33.

DOCKET NO. E-2, SUB 867

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Farnell Shingleton, 12919 US Hwy 17 N., Wilmington, North Carolina 28411, Complainant v. Progress Energy Carolinas, Inc., Respondent	))))))))	SUMMARY JUDGMENT ORDER

BY THE COMMISSION: This docket involves a complaint that was filed by Farnell Shingleton (Complainant) against Progress Energy Carolinas, Inc. (Progress), on May 6, 2005. Complainant alleges that he needs primary electric service for a residence and a horse barn that he is constructing on his farm and that he has been unable to get a right of way for the electric line from the adjoining landowners. (It appears that Complainant has secondary electric service to his property by way of a line that Progress installed some time ago; however, this secondary service will not support the load of the new buildings and, furthermore, Progress does not have any written easement for the secondary line and Complainant's immediately adjoining neighbor, Donald Sullivan, is demanding that Progress remove from his property the pole that is providing this secondary service to Complainant.) Complainant asks the Commission to order Progress to initiate condemnation in order to provide primary electric service to his property.

Progress filed an answer on May 31, 2005, subsequently verified on July 25, 2005, in which it reviews the unsuccessful efforts to get primary service to the farm. Neither Complainant nor Progress has been able to obtain the necessary right of way, and Progress states that there are only two options: Complainant can bring a legal action against a neighbor for an easement or Progress can initiate condemnation. Progress will not initiate condemnation absent an order from the Commission.

On June 8, 2005, Progress filed a motion alleging that the adjoining property owner Sullivan had asked Progress to remove Progress's pole from his property and had threatened to cut the pole down if Progress does not remove it and that removing this pole would require disconnecting the existing secondary service to Complainant's property. Progress asked the Commission for an order requiring it to maintain the existing electric service to Complainant pending the Commission's final ruling in this docket. The Commission issued an order on June 9, 2005, requiring Progress to maintain the status quo pending a decision herein.

On June 17, 2005, Complainant filed a response to Progress's answer in which he again asked the Commission to order Progress to initiate condemnation. He asked for an evidentiary hearing, but only if the Commission is unable to grant relief without one.

The Commission issued on order on June 23, 2005, holding its decision as to how to proceed in abeyance in order to give the parties an opportunity to make further filings. The Commission asked the Public Staff to intervene and participate as a party.

On June 27, 2005, Progress filed a motion for summary judgment. Progress argues that condemnation should be a last resort, that Complainant has not exhausted all remedies available to him, and that Complainant should initiate "court proceedings to acquire an easement for utility services."

On July 15, 2005, the Public Staff moved for summary judgment in favor of Complainant in the form of an order requiring Progress to pursue condemnation. The Public Staff states that Progress has cited no authority for a legal action by Complainant to establish a utility easement and that the Public Staff "could find no authority for a landowner to do so or even the possibility that such a right exists." The Public Staff argues that Complainant's right of access to his property does not give him a right to establish an electric line along the same route since a utility easement would be an additional burden on the right of way. The Public Staff recognizes that condemnation must be used for a "public use or benefit"; however, the Public Staff cites Carolina Telephone v. McLeod, 321 NC 426 (1988), which upheld use of condemnation to establish service to a single telephone customer, and argues that electric service is even more important and necessary than telephone service.

Complainant filed an affidavit in support of summary judgment on July 6, 2005. Complainant asks that Progress "use resources available only to them to help me get power." He denies the suggestion in Progress's filings that he is responsible for his neighbors' lack of cooperation. As to cost, Complainant says that he will "follow any directive" from the Commission.

On July 27, Progress filed a response. Progress says that it has a tariff requiring a new customer to provide any necessary right of way across private property and that Complainant has not complied with the tariff. Progress again argues that Complainant should be required to go to court first. Progress says that requiring it to initiate condemnation is a "far-reaching concept of momentous consequences..." Progress discusses North Carolina case law and argues that "condemnation of a neighbor's land to extend electric service to the Complainant and no one else is ... not 'for the public use [or] benefit,' and would thus be inappropriate." Finally, if Progress is required to initiate condemnation, Progress says that Complainant should bear the cost and Progress wants to collect a deposit from Complainant up front, subject to true-up.

Although findings of fact are not appropriate in an order of summary judgment, the Commission believes that it would be helpful to summarize some of the uncontroverted material facts which form the basis for the Commission's decision. It appears from the verified filings herein that the following is not in dispute:

In 1975 the farm in question was owned by Ezra Dale, and he had access to it by an unpaved logging road that traversed timberland that was owned by Weyerhaeuser Company. Dale asked Progress (then Carolina Power and Light Company) for underground primary service to the farm. In 1976 Progress installed 4900 feet of underground primary line down the center of the logging road to a transformer on Dale's property and an underground service line from the transformer to a mobile home. Weyerhaeuser gave Progress an easement, but the easement contained a condition that it would terminate if Progress ceased to use the line for two consecutive years.

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Complainant bought the farm from Dale around 1982. Weyerhaeuser sold the timberland, and it was eventually subdivided into tracts on either side of the logging road. The owners of these tracts own the logging road, now called Saps Road. The road dead-ends at a creek, and Complainant's property begins across the creek. Complainant has the right to use Saps Road for access to his property. In the mid-1990s, Progress decided to abandon the underground electric line under the road and replace it with an overhead primary line down the side of the road. The easement for the underground line therefore expired two years after it was abandoned. Progress obtained only verbal authority from the Saps Road property owners when it installed the overhead line; Progress does not have any written easements for the line. The last pole at the end of the road is about six feet short of Complainant's property. There is a transformer on the last pole and, from there, an underground secondary line runs onto Complainant's farm.

In 2004, Complainant began constructing a horse barn and other equestrian facilities on his farm. In 2005, Complainant began constructing a residence on the farm. Complainant has asked Progress to extend electric service to these buildings. The load of these buildings will be such as to require primary electric service. Extending a primary line from the last pole at the end of the road requires a right of way. Sullivan owns the last 165 feet of Saps Road, including the site of the last pole. Sullivan refuses to give a right of way for the extension of the line and is demanding that Progress remove the pole that is providing service to Complainant. Complainant tried to purchase a right of way from his neighbors, but was unsuccessful. Progress considered alternative routes and approached other landowners, but none of them would give a right of way. Four County Electric Membership Cooperative has service territory on the other side of Complainant's farm, but it does not have any lines nearby and is not interested in serving Complainant.

Summary judgment is appropriate if there is no genuine issue as to any material fact and a party is entitled to judgment as a matter of law. The Commission believes that the material facts necessary to a decision as to this complaint are not in dispute and that no evidentiary hearing is necessary. The Commission concludes that this is an appropriate case for summary judgment. The Commission will not grant Progress's motion for summary judgment. Progress argues that Complainant should be required to initiate a civil action to acquire an easement for the electric line needed to serve him, but Progress cites no authority for such an action and the Commission is aware of none. Such a course of action offers no promise to resolve this matter. The Commission will instead allow the motion filed by the Public Staff for summary judgment in favor of Complainant for the reasons that follow.

Progress has an exclusive utility franchise for the service territory that includes Complainant's farm, and Progress has an obligation to serve those who need electricity within its service territory. Progress has been given the power of eminent domain as an incident of its utility franchise. G.S., Chap. 62, Art. 9. Where necessary (assuming of course that a credible argument for public use or benefit can be made), the Commission believes that Progress should use its power of eminent domain to establish service to new customers. The Commission is not persuaded by Progress's claim that requiring condemnation will have far-reaching consequences. The times when condemnation will be necessary are few. In most cases, the necessary rights of way are obtained through cooperation, and there is no reason to think that this will change. This is the only time the Commission has ordered condemnation since 1991.[1] The Commission recognizes that Progress has a tariff requiring a new customer to provide to the utility any necessary right of way across private property, but the Commission does not believe that this tariff was ever intended to deny service altogether to someone in Complainant's predicament or to absolve Progress of its responsibilities as a public utility.

The McLeod case is very similar to the present situation; the major distinction is that it involved telephone service rather than electric service. The utility in McLeod had installed a telephone line to a single customer without getting an easement from the intervening landowner and that landowner demanded that the line be removed. The customer filed a complaint with the Commission, and an order was issued requiring restoration of service, by use of condemnation if necessary. On appeal, the North Carolina Supreme Court ruled that the provision of telephone service to a single customer was for a "public use or benefit" and upheld summary judgment in favor of the utility's exercise of condemnation. The Supreme Court reasoned that once the telephone line is established, all of the public can use it to call in and out, and, moreover, that "once installed, access to telephone service would be available at the location to [the customer's] successors in title or possession." 321 NC at 431.

Progress tries to distinquish McLeod by arguing that telephone service has a greater "social impact" than electric service. The Commission does not agree. One of the reasons given in support of condemnation in McLeod was that the telephone service would be available to the original customer's "successors in title or possession," i.e., to successive purchasers or renters, which makes for a greater "public use" than just the first customer alone. This reason applies with equal force to electric service. The Commission agrees with the Public Staff that public policy supports making adequate and reliable electric service available for all residents of the State. G.S. 62-2(a). Electric service contributes to the public welfare and prosperity, and the Commission is not prepared to say that electric service serves less of a public benefit than telephone service. See McLeod, 321 NC at 432-3. The Supreme Court cited in McLeod a Texas case which held that providing electric service to a single customer was a public use, Dyer v. Texas Electric Service Co., 680 SW2d 883 (Tex. App. 1984) ("Texas courts have made it clear that it is the character of the right which inures to the public, not the extent to which the right is exercised, that is important in evaluating enterprises which are involved in condemning private property....'The mere fact that the advantage of the use inures to a particular individual or enterprise, or group thereof, will not deprive it of its public character.'" Id. at 885). Finally, the Supreme Court said in McLeod that "the phrase [public use or benefit] is elastic and keeps pace with changing times." This echoes language from the earlier case of Charlotte v. Heath, 226 NC 750 (1946). Progress relies heavily upon Heath, but the Commission finds nothing in Heath to cast doubt on the summary judgment granted herein. In Heath, the North Carolina Supreme Court stated that no one definition of public use can be devised since, "with the progressive demands of society and changing concepts of governmental function, new subjects are constantly brought within the authority of eminent domain." Id. at 755. The Court also said in Heath that the public nature of a utility project "cannot be made to depend on a numerical count of those to be served or the smallness or largeness of a community." Id.

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[1] The last time was Tucker v. Duke Power in 1991, where the surrounding landowners refused to give rights of way and an order was issued requiring Duke to pursue condemnation in an effort to secure a right of way to provide electric service to a landlocked 20-acre tract of undeveloped land owned by Tucker and his wife.

The Commission notes that Progress's July 27 response refers to Complainant's "apparent intent" to use some of his farm for commercial purposes and suggests that this may be a concern to Complainant's neighbors. The reference to commercial uses is unverified. What is verified and uncontroverted is that Complainant is building a residence and a horse barn on his farm and that he has requested electric service for these buildings. If Complainant's neighbors have concerns as to other uses of the property, they may pursue those concerns as appropriate, but it is not appropriate for either the Commission or Progress to take sides in such a neighborhood dispute or for such considerations to control the manner in which Progress fulfills its public utility responsibilities.

The Commission believes that the provision of electric service to the Complainant herein is a matter of public use or benefit, but the Commission recognizes that the ultimate determination of public use or benefit in a condemnation proceeding must be made by the courts. McLeod, 321 NC at 429. The Commission believes, for the reasons cited above, that a strong and convincing argument can be made for Progress's invoking its power of eminent domain to establish electric service to Complainant, and the Commission believes that Progress should make that case in court. The Commission therefore orders Progress to pursue condemnation forthwith and in good faith in an effort to secure a right of way, by whatever route it finds most efficient, to provide primary electric service to Complainant's property. The Commission directs Progress to provide copies of all its filings in this condemnation proceeding to both Complainant and the Public Staff, and the Commission asks the Public Staff to monitor the progress of the proceeding for the Commission.

As to responsibility for the cost of condemnation, there are countervailing arguments. On the one hand, Progress has a tariff requiring new customers to provide any right of way across private property necessary for establishment of service. Complainant cannot comply with the tariff, and putting some cost responsibility on Complainant would be one way of giving effect to the tariff without denying him service. On the other hand, to the extent that condemnation serves the public use or benefit, this argues for Progress's bearing responsibility for the cost. The Public Staff states that this issue can be considered later, much the way a contribution in aid of construction would be considered. The Commission agrees that it is premature to address the issue of cost at this time. The amount of the cost to establish a right of way to serve Complainant's property is unknown, and the Commission will not require Complainant to make any kind of contribution or deposit up front. Progress may bring this issue back for decision at an appropriate time.

IT IS, THEREFORE, ORDERED as follows:

1. That the motion for summary judgment filed by the Public Staff should be, and hereby is, allowed and Progress shall pursue condemnation forthwith and in good faith in an effort to secure a right of way, by whatever route it finds most efficient, to provide primary electric service to Complainant's property and

2. That Progress shall provide copies of all its filings in this condemnation proceeding to both Complainant and the Public Staff and the Public Staff shall monitor the proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of August, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Ah081705.06

Commissioner Robert K. Koger did not participate in this decision.

DOCKET NOS. E-7, SUB 757 AND 759

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-7, SUB 757		
In the Matter of	)	
Doretha Harper, 2814 Emerson Road,	)	
Greensboro, North Carolina 27405,	)	
Complainant #1	)	
	)	
v.	)	
	)	
Duke Power, a Division of Duke Energy	)	RECOMMENDED ORDER
Corporation,	)	DENYING COMPLAINTS
Respondent	)	
	)	
Docket No. E-7, SUB 759	)	
In the Matter of	)	
Michael Coleman, 1019 Warehouse Street,	)	
Greensboro, North Carolina 27405,	)	
Complainant #2	)	
	)	
v.	)	
	)	
Duke Power, a Division of Duke Energy	)	
Corporation,	)	
Respondent	)	

HEARD IN: The Guilford County Courthouse, Courtroom 3B, 201 S. Eugene Street, Greensboro, N.C. on Thursday, December 16, 2004, at 10:00 a.m.

BEFORE: Corrie Foster, Hearing Examiner

APPEARANCES:

For the Complainants:

Doreta Harper, Pro Se, 2814 Emerson Road, Greensboro, North Carolina 27405,

Michael Coleman, Pro Se, 1019 Warehouse Street, Greensboro, North Carolina 27405.

For the Respondent:

Laura Nichols, Attorney at Law, Duke Power, A Division of Duke Energy Corporation, 422 S. Church Street, PB053, Charlotte, North Carolina 28202

BY THE HEARING EXAMINER: On August 4, 2004, Doretha Harper (Complainant #1) filed a complaint against Duke Power (Respondent) for unreasonable and unjust requirement for new security deposit for her residential account.

On August 11, 2004, Michael Coleman (Complainant #2) filed a complaint against Duke Power (Respondent) for unreasonable and unjust requirement for new security deposit on his business account.

On August 25, 2004, Respondent made a filing with the Commission to consolidate the dockets and requested an extension of time. The Respondent alleges that Complainants are husband and wife and that they raise similar issues in their complaints.

On August 30, 2004, the Commission issued an Order Consolidating Complaints and Granting Extension of Time.

On September 8, 2004, the Commission issued an Order Serving Answers to Complainants requesting Complainants to review the Answers and reply or request a hearing by September 23, 2004.

On September 20, 2004, Complainants made filings with the Commission indicating that the Answers filed by Respondent were not satisfactory to them and they requested a public hearing in order to present evidence in support of their complaints.

On October 5, 2004, the Commission issued an Order Scheduling Docket for hearing on Tuesday, November 16, 2004, at 10:00 a.m. in the Guilford County Courthouse, Courtroom 3D, 201 S. Eugene Street, Greensboro, NC.

On October 11, 2004, Respondent orally informed Commission Staff that its essential and necessary witness Barbara G. Yarbrough had a schedule conflict and would be unable to attend the hearing and requested a continuance.

On October 12, 2004, the Commission issued an Order Granting Oral Motion to Reschedule Hearing for Thursday, December 16, 2004, at 10:00 am in the Guilford County Courthouse, Courtroom 3B, 201 S. Eugene Street, Greensboro, NC.

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The hearing was held on Thursday, December 16, 2004, at 10:30 a.m. in the Guilford County Courthouse. Testimony and exhibits were presented by all parties. Complainants Doretha Harper and Michael Coleman, and Respondent's witness Barbara Yarbrough, Duke Power Specialist, testified.

At the conclusion of the hearing, the parties were given 30 days after the release of the hearing transcript in order to submit proposed orders.

Upon consideration of the testimony and filed exhibits from the parties, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. Respondent Duke Power, a division of Duke Energy Corporation, is a public utility providing electric utility service to customers in North Carolina subject to the jurisdiction of the Commission.

2. Complainant #1 Doretha Harper resides at 2814 Emerson Road, Greensboro, North Carolina, where she is a customer of Duke.

3. Complainant #2 Michael Coleman is Mrs. Harper's spouse and resided at 2814 Emerson Road, Greensboro, North Carolina, during the period of time at issue in these Complaints. Mr. Coleman operates a business at 1019 Warehouse Street, Greensboro, North Carolina, where he is a customer of Respondent.

4. Mrs. Harper established her residential service account with Respondent in 1990. At that time Respondent required payment of a security deposit of $125.00. Although Mrs. Harper did not establish satisfactory credit as defined by Commission Rule R12-2, Respondent refunded this deposit after several years pursuant to Rule R12-5, which gives utilities the option to refund deposits any time earlier than required by the rule.

5. Over the last 4 years, Mrs. Harper and Mr. Coleman have established a payment pattern on the residential account of normally paying only the portion of the bill that is 60 days in arrears and making such payment on or about the day before the scheduled disconnection date. Mr. Coleman typically made these payments at the same utility payment center in Greensboro by either paying the teller or placing the payment in the drop-box provided.

6. On June 11, 2003, Respondent disconnected service to Mrs. Harper's residence for nonpayment. Respondent's records indicate that it received a partial payment of the past due amount on the day of disconnection. After receiving a call from Mr. Coleman alleging that he had placed the payment in the utility payment center drop box about 4:40 pm on the previous day, Respondent agreed to reconnect the service without requiring payment of the remaining past due amount or a reconnection fee.

7. On March 17, 2004, Respondent again disconnected service to Mrs. Harper's residence for nonpayment. Respondent's records indicate that it received a partial payment on the day of disconnection. After determining that this partial payment of the past due amount had been misapplied to the nonresidential account in Mr. Coleman's name, rather than the residential

account in Mrs. Harper's name, Respondent agreed to reconnect the service without requiring payment of the remaining past due amount or a reconnection fee.

8. In addition to the disconnections for nonpayment, Ms. Harper's billing history reveals that since she first established credit the monthly usage has increased, the amount of the unpaid balance from month to month has increased and the number of months in which no payments are made have increased.

9. Mrs. Harper's billing history for her current residence dates back to August 9, 2000. Since that time, she has unpaid balances ranging from the lowest of $146.69 to the highest of $980.24. Her payment history in 2003 indicates that she made no payment on the account during the months of February, May, July, September, and November.

10. Mr. Coleman established his nonresidential service account with Respondent in 1996. Respondent did not require payment of a security deposit at that time.

11. Over the last 4 years, Mr. Coleman has established a payment pattern on the nonresidential account of normally paying only the portion of the bill that is 60 days in arrears and making such payment on or about the day before the scheduled disconnection date. Mr. Coleman typically made these payments at the same utility payment center in Greensboro by either paying the teller or placing the payment in the drop-box provided.

12. Mr. Coleman's business account at 1019 Warehouse Street, Greensboro, NC, shows that from August 14, 2001 to December 4, 2004, his unpaid balance at its lowest amount was $130.84 and $906.52 at its highest.

13. In 2002, Respondent evaluated its deposit policy in light of a substantial increase in the amount of charge offs for uncollectible bills over the period 1999 through 2001. Respondent determined that it could no longer be as lenient in the collection of deposits and re-establishment of credit. Subsequently, Respondent began reviewing electric service accounts to increase security for accounts with poor payment history.

14. Two different groups within Respondent's company review delinquent accounts for residential and non-residential accounts to evaluate the need for additional security. Disconnections for nonpayment trigger review of residential accounts and nonresidential accounts are reviewed if they are not secured and have balances in arrears. Material changes in the credit risk are also considered.

15. Commission Rule R12-3(a) provides: "An applicant for service who previously has been a customer of the utility and whose service has been discontinued by the utility during the last twelve months of that prior service, because of nonpayment of bills, may be required to reestablish credit in accordance with Rule R12-2. Rule12-3(c) further provides: "A customer may be required to reestablish his credit in accordance with Rule 12-2 . . . in case the conditions of service or basis on which credit was originally established have materially changed."

16. Respondent reviewed Mrs. Harper's residential account after service had been disconnected on two occasions for non-payment during a twelve-month period, and on April 13, 2004, assessed a security deposit of $375.

17. Respondent reviewed Mr. Coleman's business account based upon the amount of arrearage and determined that the payment history indicated the need for a security deposit. By letter dated May 25, 2004, Respondent notified Mr. Coleman that if he did not bring the account current within thirty days it would require a deposit of $560. Respondent subsequently billed the account a $560 deposit on July 13, 2004.

18. In response to Mrs. Harper's and Mr. Coleman's complaints to the Commission regarding the requirement of security deposits on each of their accounts, Respondent suspended the disconnection process. Respondent appropriately required the Complainants to make payment for the amounts not in dispute.

19. Requiring the Complainants to reestablish credit by paying a security deposit of $375 for the residential account and $560 for the nonresidential account is consistent with the Commission's policy and rules with respect to reestablishment of credit and customer deposits.

DISCUSSION AND CONCLUSIONS

Prior to addressing the initial issues in the complaints, the Hearing Examiner had to address the fact that Complainant #2, Mr. Michael Coleman, sought to represent Mrs. Harper in her complaint proceeding against Duke Power (Respondent). Mrs. Harper initially indicated that she would not testify but would allow Mr. Coleman to speak on her behalf. The Hearing Examiner was concerned that Mr. Coleman acting in a representative position of Mrs. Harper could be viewed as the unauthorized practice of law before the Commission.

Prior to taking any testimony, the Hearing Examiner conducted a brief inquiry as to the relationship between Mrs. Harper and Mr. Coleman, and his knowledge of the account in question. Through the inquiry, the Hearing Examiner learned that the Complainants are husband and wife and at the time the dispute arose regarding the security deposit, Mr. Coleman was residing in the marital home located at 2814 Emerson Road, Greensboro, North Carolina 27405. Before the complaints were filed, they separated and Mr. Coleman left the residence. He had been the primary person responsible for paying the household bills. As such, he has personal knowledge of the issues that will be addressed before the Hearing Examiner.

Based on the above information, Mr. Coleman was permitted to testify as to his personal knowledge of the account at 2814 Emerson Road in Greensboro, since he was a resident of the household at the time service was active.

The issues in both complaints involve the application of a security deposit. Mr. Coleman and Mrs. Harper, argue that it is unjust and unreasonable for Respondent to apply a security deposit on their respective accounts on the basis that they are historically late with payments. Mrs. Harper specifically, argues that Respondent should not be able to apply a security deposit due to recent disconnections because they were not due to nonpayment but were due to an error by the utility. Mrs. Harper further argues that, even though she has a late payment history, Respondent should not be allowed to arbitrarily impose a security deposit on her account.

Mr. Coleman, in this case, argues that Respondent has no basis for imposing a security deposit on his business account. He believes that Respondent is simply retaliating against him for fighting Respondent's unfair billing practices with his wife.

In response, Respondent argues that it is merely attempting to reduce its increasing uncollectible accounts. While addressing the growing concern over uncollectible accounts, it is following provisions in its tariff and the Commission Rules. Respondent further argues that it has not sought to discriminate or retaliate against Mr. Coleman and the imposition of a security deposit upon his account was coincidental. Respondent notes that it is relying on Commission Rules R12-3(a). In the alternative, Respondent argues that Rule R12-3(c) is appropriate to both accounts because Complainants' payment histories demonstrate that there is a material change in the accounts and they are at risk of not getting paid.

The Hearing Examiner has some sympathy with Complainants in their current predicament with the utility. However, there does not seem to be much support for Complainants' position in this docket. The Hearing Examiner does agree with Mrs. Harper that a security deposit should not be imposed upon her under the disconnect provision of Commission Rule R12-3(a). Clearly there is convincing information to support the finding that the two specified disconnects were not entirely the result of the actions of the Complainants.

On June 11, 2003, Complainants' service was apparently disconnected for nonpayment. There was obviously some dispute between the parties as to when exactly the payment was made. Complainants argued that they placed payment in the payment box at or around 4:50 p.m. the day of tentative shut off. However, Respondent alleged that the payment was not recorded as being received until the next day. Mr. Coleman argued further that it was the responsibility of the utility to ensure that it retrieved payments out of the box by 5:00 p.m. each day and ensure that its agent appropriately applied the payment to the correct account. Although the Hearing Examiner would agree that Respondent's agent has a responsibility to ensure that payments are promptly applied to the customer's account, the customer has a dual responsibility to ensure that payments are made timely. If payments are not made on a timely basis and termination is effected, the burden falls on the customer to prove that termination was unjust and unreasonable given the facts. That is a situation which is easily avoided by paying timely.

In this case, the burden of proof is moot. Respondent in its answer filed with the Commission on September 2, 2004, gave Mr. Coleman the "benefit of the doubt", reconnected service, and waived the reconnection fee. Although there was some question as to when exactly the payment was made, there was no incontrovertible evidence that Mr. Coleman did not make the payment before 5:00 p.m. Therefore, like the Respondent, the Hearing Examiner will give Mr. Coleman the "benefit of the doubt" and find that the payment in question was submitted before or on 5:00 p.m., the scheduled deadline for disconnection.

On March 17, 2004, Complainants' residential service was disconnected a second time. Apparently, Respondent had inadvertently applied the payment to Mr. Coleman's business account and not the residential account. There was no definitive information to support the allegation that the payment was received late and the service should have been terminated. Respondent in its answer to the complaint, indicates that it was unable to admit or deny whether the payment was received in time to avoid disconnection. Due to the error, Respondent did not charge Complainant a reconnection fee to continue service. Given the circumstances surrounding the payment and the lack of indisputable evidence that the payments were not received before the termination deadline, the Hearing Examiner does not find that this was a valid disconnect of service.

These two instances mentioned above should not be used as a basis to seek a security deposit under Rule R12-3(a). However, the Hearing Examiner does believe that Respondent has a basis under Rule R12-3(c) to pursue a security deposit. Rule R12-3(c) provides in part, that "A customer may be required to reestablish his credit in accordance with Rule R12-2 . . . in case the conditions of service or basis on which credit was originally established have materially changed."

According to Commission Rule R12-1, the Commission declares that it is in the public interest that any utility requiring a deposit from its customer shall fairly and indiscriminately administer a reasonable policy reflected by written regulations, in accord with these rules, for the requirement for a deposit ... for an existing customer to continue service.

In this docket, the facts indicate that Complainants are routinely late making payments and always maintain a past due balance on their accounts. However, Mr. Coleman argues that there has been no material change in their account because they have always paid late and this is their normal practice. To him this practice is acceptable because he and Mrs. Harper pay prior to the termination of their service. This is not a compelling argument. Although there is no prior Commission case on point, the Hearing Examiner looks at Treglia v. Carolina Power and Light Co. E-2, Sub 679 (July 12, 1995) for guidance in understanding what material change means. In this case, the Complainant argued he should not be required to submit a security deposit because he had met the requirement for reestablishing credit in accordance with Rule R12-2 in the case the conditions of service or basis on which credit was originally established have materially changed. The Complainant submitted a letter of credit from Duke Power, however the letter was deemed inadequate by CP & L because it showed a poor payment history. The Commission granted Summary Judgment to CP& L on the basis that service was extended to Treglia in reliance upon the statement that he would provide a satisfactory credit reference letter from Duke Power. When the credit reference proved unsatisfactory, a material change in the basis on which credit was extended to him existed. The premise is the same in this docket. Respondent provided service with the belief that Complainants would maintain a good credit history by making timely payments on their service. The Hearing Examiner does not believe there is such a thing as "perfect credit". However, it is not inconceivable that a customer's credit rating is affected by the extent that he/she pays her bills. In Commission Rule R12-11(a) Disconnection of Residential Customer's Electric Service, the Commission addresses the issue of credit in such a fashion. Specifically, the rule notes that payment of a bill after the specified due date could result in the lowering of a customer's credit code rating to one which permits the utility to disconnect on an earlier date.

It would be difficult for Mrs. Harper to claim that late payments and high past due balances are evidence of someone maintaining a good credit rating. Complainants' billing history for their current residence dates back to August 9, 2000. Since that time, they have unpaid balances ranging from the lowest of $146.69 to the highest of $980.24. Mrs. Harper's payment history in 2003 indicates that she made no payment on the account during the months of February, May, July, September, and November.

Mr. Coleman and his wife pay some of their bills. However, they pay late and never in full. During the evidentiary hearing, Mr. Coleman testified that in his business he expects his customers will pay late. To him, this is an acceptable practice. Despite his contentions otherwise, the Hearing Examiner doubts that Mr. Coleman would continually provide service to a customer who does not make timely payments or only pays a fraction of what is owed. Mr. Coleman attempts to employ the same argument he uses for the residential account for his business account. Unfortunately, he fails to meet his burden of proof in this claim as well.

Even though a security deposit was initially not obtained on his business account, Mr. Coleman's payment practice has made it reasonable and necessary to seek some type of security deposit. At some point, some security must be established. A security deposit is meant to provide some incentive to the customer to maintain good credit with the utility. If good credit is maintained, then the deposit is returned to them at some point. If good credit is not maintained and service is terminated, the customer can use the security deposit towards the past due balance. Thus, the Hearing Examiner would not expect Respondent to continue to provide service to a customer that habitually pays late and has a growing past due balance without seeking some form of security.

Mr. Coleman does not present a convincing argument why his business account should be treated any different from his residential one. Mr. Coleman's business account at 1019 Warehouse Street, Greensboro, NC, shows that from August 14, 2001 to December 4, 2004, his unpaid balance at its lowest amount was $130.84 and $906.52 at its highest. Although he accepts the belief that late payments and unpaid balances are the norms in his business, the Hearing Examiner does not share that belief. The Hearing Examiner understands the reasons behind Respondent's initiative to review its policy on obtaining security deposits on at risk accounts.

It does not appear that Respondent's actions were discriminatory or selective. As indicated in the pleadings, Respondent is reacting to an increasing financial problem, the loss of uncollectible accounts. As such, it has begun to tighten its credit policies and has requested a security deposit from certain customers. Two different groups within Respondent began reviews of delinquent accounts for residential and non-residential accounts to evaluate the need for additional security. Disconnections for nonpayment trigger reviews of residential accounts and nonresidential accounts are reviewed if they are not secured and have payments in arrears. Unfortunately, Complainants fit in both of these categories.

Respondent is not arbitrarily denying service. Respondent has been clear to notify Complainants in its Answer that they can reestablish satisfactory credit according to Commission Rule R12-2. This Rule allows for customers to submit credit references or a guarantor to secure payment of bills.

For the reasons set forth above, the Hearing Examiner finds that the Complainants have not met their burden of proof and denies the complaints.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of May, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah052505.03

DOCKET NO. E-7, SUB 757
DOCKET NO. E-7, SUB 759

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 757 In the Matter of Doretha Harper, 2814 Emerson Road, Greensboro, North Carolina 27405, Complainant, v. Duke Power, a Division of Duke Energy Corporation, Respondent	)	
DOCKET NO. E-7, SUB 759 In the Matter of Michael Coleman, 1019 Warehouse Street, Greensboro, North Carolina 27405, Complainant, v. Duke Power, a Division of Duke Energy Corporation, Respondent	)	FINAL ORDER OVERRULING EXCEPTIONS AND AFFIRMING RECOMMENDED ORDER

HEARD: Monday, September 26, 2005, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, Commissioners Robert V. Owens, Jr., Sam J. Ervin, IV, James Y. Kerr, II, and Robert K. Koger

APPEARANCES:

For Complainants
No attorney of record

For Duke Power, a Division of Duke Energy Corporation:
Robert W. Kaylor, 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

BY THE COMMISSION: On August 4, 2004, Doretha Harper filed a complaint against Respondent Duke Power, a Division of Duke Energy Corporation (Duke), regarding an assessment of a security deposit against her residential electric service account. On August 11, 2004, Michael Coleman filed a similar complaint regarding an assessment of a security deposit against his non-residential electric service account. The complaints were consolidated for hearing, which was held on December 16, 2004, before Hearing Examiner Corrie Foster. A Recommended Order Denying Complaints was issued on May 27, 2005.

On August 1, 2005, Complainants Harper and Coleman jointly filed exceptions to the Recommended Order and requested oral argument. On August 10, 2005, the Commission issued an Order Scheduling Oral Argument on Exceptions.

On September 21, 2005, Complainant Harper filed a letter with the Commission stating that she no longer wanted to pursue her complaint against Duke.

The matter came on for oral argument, as ordered, on September 26, 2005. Complainant Coleman and counsel for Duke were present and made oral argument. The Presiding Commissioner ruled that Ms. Harper's letter would be treated as a request to withdraw the exceptions previously filed in Docket No. E-7, Sub 757 and that such request would be granted.

During his argument, Mr. Coleman acknowledged that he maintains an outstanding balance on his electric service account and that he consistently pays his non-residential bill on the last day allowed by the utility in order to avoid disconnection. He argues, however, that his payment history does not justify Duke's request that he now post a $560 cash deposit in order to maintain electric service. Just as he is required to comply with the utility's payment guidelines to avoid disconnection, Duke should be required to comply with the Commission's Rules and Regulations regarding customer deposits.

Mr. Coleman argues that Rule R12-3, which governs reestablishment of credit by existing or returning customers, does not justify the imposition of a deposit requirement in this instance. First, Mr. Coleman notes that Rule R12-3(a) is inapplicable here because it applies only to customers whose service has been disconnected, and his non-residential account has never been disconnected for non-payment. Second, Mr. Coleman argues that Rule R12-3(c) is inapplicable here because it applies only to customers for whom "the conditions of service or basis upon which credit was originally established have materially changed." Rule R12-3(c). He argues that there has been absolutely no change in his nine-year payment history, but that he has always paid on the last day allowed by the utility in order to avoid disconnection. In addition, argues Mr. Coleman, contrary to the case cited in the Recommended Order, there has been no material change because "[a]t no point in time have I told Duke Power I got good credit and I pay on time." Thus, since there has been no change, he cannot be now required to post a deposit. Rather, he alleges, Duke is requiring a deposit in retaliation for his becoming involved in his wife's complaint. Lastly, he argues that Duke is now attempting to justify their actions by including him in a new group of customers identified as "slow payers" from which it asserts the right to collect a deposit under the pretext of Rule R12-3. Such an attempt to impose a new deposit requirement, he argues, is not allowed under the Commission's Rules and should be rejected by the Commission. Mr. Coleman argues that such a requirement would apply not only to himself but also to a large number of Duke's customers, and that it would authorize Duke to collect new deposits from all current slow-paying customers. Neither he nor these other customers should be punished for paying their electric utility bills within the guidelines established by Duke and the Commission.

In response, Duke argues that Rule R12-1, which contemplates that a cash deposit may be required of an existing customer to "maintain" or to "continue" service, authorizes the company to collect a deposit from an existing customer upon review of that customer's billing history. Duke argues that it is not discriminating against Mr. Coleman, as he alleges, but rather has applied its policy affecting slow payers uniformly. In Mr. Coleman's case, Duke states that it has been "very liberal" in administering its cut-off policy: "We could actually cut him off before he comes in on his 60th day, but we treat businesses like him the same as residential." Nevertheless, Duke argues that its concerns over slow payers and the impact to the remaining ratepayers if these balances ultimately are not paid justify the review of such accounts and the requirement of a cash deposit from such customers.

. After careful consideration of the record and arguments presented, the Commission concludes that habitual late payments by a customer may be considered a material change in the "basis upon which credit was originally established" and that Duke's policy of requiring slow-paying customers to reestablish credit upon review of their payment history is reasonable. Mr. Coleman argues that there has been no material change in his case because he has always paid late. Moreover, he argues that Duke had no expectation upon opening his account that he would pay on time. The Commission is unwilling to agree with Mr. Coleman on this point. Rather, the Commission concludes that it is reasonable for Duke to assume, as a condition of establishing a new account, that the customer will pay its bills when they are due and not habitually pay at the last minute in order to avoid disconnection. Commission Rule R12-2(b) states that the establishment of credit, as was apparently done when Mr. Coleman initially opened his account, "shall not relieve the applicant for service or customer from compliance with the reasonable regulations of the utility including, but not limited to, the prompt payment of bills." A payment history to the contrary, therefore, may be considered a "material change" in the customer's creditworthiness sufficient to require the customer to post a cash deposit or otherwise reestablish credit in order to maintain service.

The Commission is mindful of Mr. Coleman's concern with regard to the potential for the utility to require such deposits from a significant number of customers from whom they currently have none. However, the Commission concludes that its other Rules and Regulations with regard to customer deposits, such as the requirement that customer deposits held longer than ninety days earn interest at eight percent, Rule R12-4(c), will appropriately discourage the utility from collecting more than the minimum deposit necessary from its customers to manage the risk of uncollectible accounts. The utility does not want to act as a bank paying higher than the current market rate interest on monies held in customer deposits. On the other hand, the utility is entitled to – indeed, is obligated to – protect itself and its ratepayers from the risk of unpaid accounts. Requiring customers to initially establish, and then to maintain, creditworthiness is a prudent business practice authorized by the Commission's Rules and is not a penalty imposed upon slow payers.

In the instant case, the Commission concludes that Mr. Coleman should be allowed an additional opportunity to pay his outstanding balance and to bring his account current before being required to post a cash deposit or otherwise reestablish credit. Thereafter, Duke shall apply its policy with respect to Mr. Coleman in the same manner that it would apply the policy to any other customer.

IT IS, THEREFORE, ORDERED as follows:

1. That the Motion to Withdraw Exceptions filed by Doretha Harper in Docket No. E-7, Sub 757 be, and the same is hereby, granted;

2. That each and every exception filed by Michael Coleman in Docket No. E-7, Sub 759 to the Recommended Order Denying Complaints issued May 27, 2005, be, and the same are hereby, overruled;

3. That Mr. Coleman shall be subject to Duke's policy regarding slow payers and shall post a cash deposit or otherwise reestablish credit in accordance with the Commission's Rules and Regulations if his balance due to Duke is not paid in full within 60 days of the date of this Order and his account thereafter kept current; and

4. That, except as modified herein, the Recommended Order Denying Complaints issued May 27, 2005, be, and the same is hereby, affirmed and adopted as the Final Order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Robert V. Owens, Jr. dissents.
Ah112905.10

DOCKET NO. E-7, SUB 757
DOCKET NO. E-7, SUB 759

COMMISSIONER ROBERT V. OWENS, JR., DISSENTING: I must respectfully dissent from my colleagues in the majority on this opinion. I do not agree that Duke should be allowed to penalize Mr. Coleman by requiring him to post a cash deposit in the amount of $560 under the facts of this case.

Mr. Coleman, while admittedly a last-minute payer, nevertheless complies with Duke's requirements for maintaining electric service. In fact, he is apparently one of Duke's most consistent customers in that he pays each month the amount of his bill absolutely required by Duke in order to avoid disconnection. As Duke admitted at the oral argument, Mr. Coleman is assessed a late charge each month as a penalty for failing to (or choosing not to) pay the bill in full by the initial due date. However, that is an economic choice Mr. Coleman has made and, in so choosing, is complying with Duke's payment rules. Mr. Coleman should not be further penalized for making this choice.

Duke further admitted at oral argument that its primary concern involves the amount of Mr. Coleman's outstanding bill as a result of his late payments. Yet, Duke stated that it is not strictly applying its business cut-off policy to Mr. Coleman, but is treating his business as if it were a residential account. Specifically, counsel for Duke stated, "We could actually cut him off before he comes in on his 60th day." If Duke is concerned about the length of time Mr. Coleman takes to pay his bill to avoid disconnect and the amount of the bill that accrues in that time, Duke should enforce its disconnect policy rather than attempt to impose a deposit requirement. Duke is not without a remedy. Unfortunately, it has not chosen to avail itself of the remedies at its disposal.

Therefore, because Mr. Coleman's payment history for the past nine years demonstrates that he has consistently paid the total amount of his bill each month absolutely required by Duke in order to avoid disconnection, because Mr. Coleman already incurs and pays a late charge as a result of this payment practice, and because Duke has other options with which to limit the amount of Mr. Coleman's outstanding balance, I cannot join in the majority's decision to allow Duke to further penalize Mr. Coleman by requiring a cash deposit in order to maintain electric service.

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

DOCKET NO. E-7, SUB 758

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Barnette Michele Ray, 4706 Cheviot Rd., Charlotte, North Carolina 28269, Complainant v. Duke Power, a Division of Duke Energy Corporation, Respondent	)	RECOMMENDED ORDER DENYING COMPLAINT

HEARD: Monday, March 7, 2005, at 10:00 am., at the Public Library of Charlotte and Mecklenburg County, 310 North Tryon Street, Charlotte, North Carolina

BEFORE: Hearing Examiner Sammy R. Kirby

APPEARANCES:

For Duke Power:
Lawrence R. Somers, Assistant General Counsel, Duke Energy Corporation, Post Office Box 1244, Charlotte North Carolina 28201-1244

For the Using and Consuming Public:
Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE HEARING EXAMINER: On November 15, 2004, Barnette Michele Ray (Complainant) filed a complaint against Duke Power, a division of Duke Energy Corporation (Duke), regarding an adjustment for an undercharge that Duke had included in her electric bill.

The Commission served the complaint on Duke by order of November 16, 2004. Duke filed an answer and offer of relief with the Commission on December 7, 2004. Duke's answer and offer of relief was served upon the Complainant by order of December 9, 2004. Complainant filed a response on December 21, 2004, requesting a hearing. The Commission entered an order of January 14, 2005, scheduling a hearing for March 7, 2005.

Complainant filed a letter with the Commission on January 14, 2005, in which she requested suspension of a payment agreement she had entered into with Duke, and Duke responded by letter filed January 26, 2005, in which Duke agreed to suspend the payment arrangement and any disconnection for nonpayment of the charges at issue pending resolution of this complaint. The Commission entered a February 2, 2005 order suspending the payment agreement for the charges in dispute and ordering that Complainant's service not be disconnected before her complaint was decided by the Commission.

Duke filed a motion for issuance of a subpoena to Piedmont Natural Gas Company, Inc. (Piedmont), on February 25, 2005, and Complainant filed an objection to the motion that same day. The Commission issued an order allowing the motion for a subpoena on February 28, 2005.

On March 3, 2005, Duke filed a request for a continuance of the March 7, 2005 hearing. Complainant filed an objection to Duke's motion on March 4, 2005, and the Commission entered an order denying the motion for a continuance on that same day.

The Attorney General filed a notice of intervention on March 4, 2005.

The case came on for hearing as ordered on March 7, 2005, and Complainant, with the assistance of the Attorney General, presented her own testimony. Duke presented the testimony of Barbara G. Yarbrough with exhibits and the affidavit of Carl Compton of Piedmont. During the course of the hearing, Duke Power renewed its motion for a continuance and, in the alternative, moved to hold the record open so that it could subpoena an additional witness and present additional testimony at a later time. The Hearing Examiner again denied Duke's motion for continuance and deferred ruling on Duke's motion to hold the record open. The Attorney General moved to strike paragraph 7 of the affidavit of Carl Compton, and this motion was taken under consideration by the Hearing Examiner.

On March 15, 2005, the Hearing Examiner entered an order ruling on the outstanding motions. The Hearing Examiner denied Duke's motion to hold the record open and granted the Attorney General's motion to strike the second sentence of paragraph 7 of the affidavit of Carl Compton.

Based upon consideration of the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. Respondent Duke is a public utility providing electric utility service to customers in North Carolina subject to the jurisdiction of this Commission.

2. Complainant resides at 4706 Cheviot Road in Charlotte, North Carolina, where she is a customer of Duke.

3. Complainant first became a customer of Duke in 1986 at an apartment, and she has had electric service accounts at different residences in Charlotte over the past 19 years.

4. Available Duke records include bills for Complainant at a one-story, 600-square-foot all-electric residence on Lookout Lane between January 1989 and May 1991. Her bills for this residence averaged approximately $69 per month, with a high bill of $111.75 and a low bill of $32.71.

5. Duke records reveal bills for Complainant at a one-story, 828-square-foot house on Rozzells Ferry Road between June 1991 and October 1998. Her bills for this residence averaged approximately $40 per month (not including the additional outside light), with a high bill of $87.32 and a low full-month bill of $16.78.

6. Complainant established electric service at her current residence in October 2000. The residence is a two-story, 1,664-square-foot house on Cheviot Road. Complainant's Cheviot Road house has electric heating, an electric stove, and electric washer and dryer. The water heater and fireplace logs use natural gas. There is a solar device on the roof of the house, but it is not clear whether it heats the house or supplements the gas water heater.

7. Complainant's initial electric bill for seven days of service at the Cheviot Road house was $10.59. Her November bill was an estimated bill for $64.85, and it was replaced with an actual bill in December 2000 for usage in both November and December of $188.93. Complainant's electric bill for January 2001 was $119.27; for February 2001, $129.94; for March 2001, $100.25; for April 2001, $98.37; and for May 2001, $65.76.

8. On May 14, 2001, Duke replaced the meter at Complainant's residence with a meter capable of sending a radio frequency signal that can be read remotely. Complainant's new meter was among the first that Duke installed as part of a plan to phase in the use of meters that can be read remotely.

9. Complainant's June 2001 bill, which covered a partial period after the meter change, was for $32.87. In July 2001, Complainant's bill was $8.19; in August 2001, $8.20; in September 2001, $8.26; in October 2001, $8.33; in November 2001, $8.13; and in December 2001, $8.13. Complainant's bills from July 2001 through May 2004 averaged $11.27, with a high bill of $34.79 in January 2004 and a low bill of $7.94 in May 2004. During this period, Complainant's monthly bill was less than $9 per month for 26 out of the 35 months.

10. Complainant's bills included Duke's basic facilities charge, which is $7.87 per month.

11. Complainant never contacted Duke about the low bills.

12. On May 28, 2004, the remote reading for the meter serving Complainant's residence was the same as for the month before, indicating zero usage for the month. Duke sent a field representative to investigate. The dials on the meter serving Complainant's residence, which had a reading of zero when installed on May 14, 2001, showed a reading of 43,327 kWh when manually read on May 28, 2004. Duke subsequently tested this meter and found that it was registering properly.

13. Although the dials on the meter indicated total usage of 43,327 kWh, Complainant had been billed based upon the readings from the radio frequency device, and these remote readings had shown total usage of only 1800 kWh, indicating that the radio frequency device had been sending incorrect signals. Complainant had been billed for a total of $394.36 for the entire three-year period since the installation of the meter.

14. Duke replaced the meter at Complainant's residence on June 10, 2004. Complainant's bills since then have been $94.20 in July 2004; $58.67 in August 2004; $116.73 in September 2004; $67.06 in October 2004; $55.13 in November 2004; $136.68 in December 2004; $251.53 in January 2005; $154.42 in February 2005; and $125.89 in March 2005.

15. Duke sent Complainant a bill which included an adjustment of $2,850.05 for actual usage during the three-year period, along with a letter explaining the underbilling and offering to discuss payment arrangements.

16. Complainant had knowledge that she was being underbilled sufficient for purposes of Commission Rule R8-44(3). Duke appropriately billed Complainant for the underbilling pursuant to Commission Rule R8-44(3), and Complainant should pay for her actual usage during the 35-month period.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

Complainant testified that she moved into her house in October 2000, that she owns the house, and that it has an electric heat pump, gas water heater and fireplace, and a "solar heating panel" on the roof. She testified that prior owners had installed the solar panel and that she "checked it out and noticed that it was connected to the...gas water heater is where it was pulling the energy from and then going up into the attic." She testified that she didn't know what was in the attic because there was no access to the attic. At another point, Complainant testified that she had gotten information when she purchased the house that the solar panel would actually heat the house. She testified that the solar panel was "connected to the gas water heater. That's the source it's pulling from. But when it's on, it's pulling the rays in. And there's a fan up in the corner of the room that pulls the heat in from the ... panel."

Complainant testified that she had been a Duke Power customer at various residences since 1986, but that she could not recall her average monthly bill. She testified that it was hard to say whether the average bill was closer to $8 a month or $100 a month. She opens the billing envelope, looks at the amount, writes the check herself, and then throws the bill away. She stated that she had never received a bill that she thought was too high or a bill that she thought was too low.

Complainant testified that during the period of the underbilling she lived in her home and worked for Better Cleaning Maintenance Supply as a sales consultant. Her supervisor was Robert Lowery. She at first testified that there was no relationship with him, but then admitted that he was her ex-brother-in-law. She would travel to solicit new accounts for the company. She testified that she traveled through the Southeast region which included North and South Carolina, Georgia, Florida, and Virginia, but she could not remember any of the locations. When asked to list the locations where she had worked, she testified that she had no addresses to give.

When asked to name some of the customers that she had called on, she testified that she didn't have that information. She testified that she worked out of town during the entire period of the underbilling and came home only once a month. When she came home, she was home for two days, Friday and Saturday, and left on Sunday. She used the washer and dryer during that time and cooked during that time.

Complainant testified that relatives would check on her house while she was away. She turned the thermostat down to 60 during the winter and left it on 65 to 70 during the summer. She left the refrigerator plugged in, but no lights on. The stove was electric and the clothes dryer was electric. She made a "guesstimate" that her monthly bills were in the range of $100 in winter and $60 in summer before the period of underbilling. She testified that when the bills dropped to about $8 a month, she didn't find that unusual since she was away. She testified that she started working for Better Cleaning Maintenance Supply in May of 2001 and stopped in June of 2004, the exact same time period as the underbilling.

Barbara Yarbrough is Duke's Manager of Regulatory Interface. She testified that Complainant's meter was one of the first installed in Duke's mobile meter reading program. The program enables Duke to read meters by simply driving a truck down a street and picking up readings which are transmitted from the meters by a radio frequency device. Yarbrough testified that Complainant moved to her current residence in October 2000, that her remote-read meter was installed on May 14, 2001, with a zero reading, that the underbilling of Complainant began in June 2001, and that her billed usage never got above 10 kWh in the summer and was a little higher in the winter. In June 2004 a "bill sort" occurred because Complainant's meter reading showed zero usage for the month. A Duke field representative was dispatched to check the dials on the meter. The dials on the meters showed a total reading since installation of about 43,000 kWh, while the readings picked up from the radio frequency device totaled only 1800 kWh. The meter was replaced on June 10, 2004, and readings thereafter returned to levels similar to those before the remote-read meter was installed. Yarbrough testified that recent bills were $125 to $250 while the majority of the bills during the underbilling months were less than $10. A corrected bill was sent charging Complainant for the actual usage during the entire 35-month period of underbilling. Yarbrough testified that Duke "took the total number of days in that period, came up with an average kilowatt hours per day of 39.6 per day, and then just put that number of kilowatt hours in each month." The difference between the corrected billing and what Complainant had paid was $2767.08 without sales tax, or $2,850.05 with sales tax.

Yarborough testified that Complainant's meter was tested and found accurate. She believes that the radio frequency device was also accurate. The radio frequency device produces readings based upon a stripe painted on a spinning disk. A defect in the stripe can cause the device to miscount the revolutions of the disk and produce an inaccurate kWh reading. Duke had other customers (about half of one percent) affected by similar malfunctions. Yarborough testified that a lot of them reported the errors in their bills, and they were billed correctly. Duke performed random checks of the remote meter readings, but Complainant's meter was not manually read until the June 2004 bill sort. Duke reports to the Commission on the accuracy of its meters, but the report does not cover the remote reading devices. Yarborough testified that Duke replaced 2 million meters over 4 years and is getting "phenomenally better results from mobile read meters [than] manual reading."

Yarborough testified that Duke looked at Complainant's billing history for prior addresses before concluding that it was appropriate to bill her for the entire 35-month period of underbilling. From October 1986 until mid-1991, Complainant's lowest bill for a 600-square-foot residence was about $32 and her highest bill was about $112. From mid-1991 until the end of 1998, most of Complainant's bills for an 821-square-foot house were in the $30 to $50 range, with one bill as low as $17. Complainant's current residence has 1664 square feet. Yarborough testified that Duke doesn't know what is happening in a customer's residence and that the customer is in a better position to know if he is being overbilled or underbilled. Yarborough testified that "customers who had service with Duke Power for more than 10 years have a feel for what it costs to operate appliances in their home." She stated that a refrigerator normally uses 100-150 kWh a month and that one load in an electric clothes dryer uses about 5 kWh.

Duke also produced Complainant's billing history from Piedmont Natural Gas Company, Inc., from May 2001 through February 2005. The records show that Complainant's natural gas usage during the period of May 2001 through June 2004 ranged from a low of 12 therms per month in the summer of 2002 up to 29 therms for January 2004. The majority of the bills showed usage of therms in the high teens or low twenties, i.e., from 15 to 25 therms. Seven bills showed usage above 25 therms. The records show a low bill of $17.42 for June 2002 and a high bill of $41.45 for January 2004. There was no dramatic change in the pattern of the bills before and after June 2004.

Commission Rule R8-44 addresses situations where an electric utility charges a customer either more or less than the amount provided by Commission-approved rates. The relevant sections of Rule R8-44 (with emphasis added) provide as follows:

> (3) If the utility has undercharged any consumer as the consequence of a fraudulent or willfully misleading action on that consumer's part, or any such action by any person other than the employees or agents of the company, such as tampering with, or bypassing the meter where it is evident that such tampering or bypassing occurred during the residency of that consumer, or <u>if it is evident that a consumer has knowledge of being undercharged without notifying the utility as such</u> the utility shall recover the deficient amount as provided by the following:
>
> a. If the interval during which the consumer was undercharged can be determined, then the utility shall collect the deficient amount incurred during that entire interval, provided that the applicable statute of limitations is not exceeded.
>
> ....
>
> (4) <u>If the utility has undercharged any consumer as the result of a misapplied schedule, an error in reading the meter, a skipped meter reading, or any other human, machine, or meter error, except as provided in (3) above,</u> then the utility shall recover the deficient amount as provided by the following:
>
> a. If the interval during which a consumer having a demand of less than 50 KW was undercharged can be determined, then the utility may collect the deficient amount incurred during that entire interval up to a maximum of 150 days....

The pertinent phrase in Rule R8-44(3) is "if it is evident that a consumer has knowledge of being undercharged without notifying the utility…." If this phrase applies, recovery for up to 3 years is allowed; if it does not apply, recovery is limited to 150 days.

The Attorney General notes that Rule R8-44(3) begins by referring to "fraudulent or willfully misleading" conduct, and he argues that the phrase "if it is evident that a consumer has knowledge of being undercharged without notifying the utility…" can be read either as "a second example that relates to willfully misleading conduct" or, alternatively, as "an additional and broader exception" independent of the earlier "fraudulent or willfully misleading" provision. The Attorney General urges that the phrase be read so as to require some sort of fraudulent or willful misconduct by the customer. He argues, "There must be proof that the consumer actually detected the undercharges and failed to notify the utility…." The Attorney General contends that the Complainant in this case had no actual knowledge of the undercharges and that Rule R8-44(3) does not apply. The Attorney General would apply Rule R8-44(4) instead, and Rule R8-44(4) limits the utility's recovery of undercharges to 150 days. Duke, on the other hand, argues that Complainant had knowledge of the undercharges, that Rule R8-44(3) applies, and that recovery should be allowed for up to the full period of the statute of limitations, which is 3 years, G.S. 1-52(1).

Given the language and construction of Rule R8-44(3), the Hearing Examiner interprets it as describing two situations -- each introduced by the word "if" and joined by the conjunction "or" -- in which a utility can recover undercharges for up to the full period of the statute of limitations. The first situation is "if the utility has undercharged any consumer as the consequence of a fraudulent or willfully misleading action on that consumer's part…." The second, independent situation is "if it is evident that a consumer has knowledge of being undercharged without notifying the utility…." For the second situation to exist, the customer must have knowledge that he was being undercharged, and the Complainant in this case denies knowledge. However, a customer's denial of knowledge is not the end of the inquiry. Knowledge is a question of fact, and circumstances may justify a finding that a person had knowledge even though he denies such. 58 AmJur2d, Notice §§39-40 and 42 (2002); 22 Strong's NC Index 4th, Notice §2 (2002).

The Attorney General cites the decision in a previous complaint case dealing with Rule R8-44(3), Cabot v. Carolina Power & Light Company, Docket No. E-2, Sub 808 (Recommended Order issued on October 25, 2002, and final on November 13, 2002).[1] In Cabot, the complainant gave an explanation for his lack of knowledge, the utility did not impeach his

[1] In Cabot, the electric utility failed to bill a customer after he moved to a newly constructed house. The customer claimed that he did not realize that he was not being billed because he assumed his wife was taking care of the electric bills and his wife assumed that he was, and they were both busy and never discussed the matter. The recommended order in Cabot found facts consistent with the complainant's testimony and limited recovery to 150 days. However, the recommended order made clear that the decision was limited to the facts therein. The recommended order stated that Rule R8-44(3) cannot be exploited by any customer simply claiming lack of knowledge because

> the Commission is the judge of credibility. Just as the student cannot get away with "The dog ate my homework," so the electric customer cannot simply say, "I didn't know. For three years, I didn't know." The Commission does not have to accept the testimony of any witness, even if uncontradicted by other evidence. Utilities Commission v. Telephone Co., 285 NC 671, 688 (1974).

92nd Report of North Carolina Utilities Commission Orders and Decisions, p. 389 (2002).

credibility during cross examination, the utility presented no evidence to contradict the complainant, and recovery was limited to 150 days. The Hearing Examiner reaches a different result in this case. In this case, in contrast with Cabot, cross examination brought out several improbabilities in Complainant's testimony. These include the exact coincidence of the underbilling and Complainant's work out of town, Complainant's inability to remember any of the customers she saw or places she went to while working out of town, and her not knowing whether her average electric bill was closer to $8 or $100 a month. Complainant testified that she was traveling out of town soliciting customers for a Charlotte janitorial service company during the period of the underbilling and that she only came home once a month; however, when pressed for details during cross-examination, Complainant could not name a single customer that she traveled to see as part of her job or a single location that she went to. In addition, in this case, Duke presented evidence of Complainant's past electric bills, which were consistently much higher than those during the period of underbilling, and evidence of Complainant's natural gas usage, which did not show any significant decline during the period when Complainant claimed to be working out of town. The Hearing Examiner, based upon his own experience and general knowledge of the natural gas industry, does not believe that Complainant's natural gas usage is consistent with that of a typical home with a gas water heater and gas logs that is occupied only one weekend a month. There was no significant change in the pattern of the natural gas bills before and after June 2004, when Complainant testified that she stopped the job for which she was traveling out of town. The Hearing Examiner's weighing of the testimony and credibility of the witnesses is key to this decision. Considering the weigh and credibility of the witnesses and the evidence overall, the Hearing Examiner finds that Complainant had knowledge, sufficient for purposes of Rule R8-44(3), that she was being underbilled for electric service. The Hearing Examiner concludes that it is therefore appropriate to allow Duke to recover the deficient amount for the full period permitted by the statute of limitations.

Testimony tends to show that the underbilling resulted from a defect in a "stripe painted on a spinning disk" used by the devices that Duke uses to send radio frequency signals and read meters remotely. The Attorney General argues that Duke's use of defective remote meter reading equipment caused the undercharges and that Duke's failure to take an actual reading of Complainant's meter during the 3-year period perpetuated the problem. The Attorney General argues that, given the circumstances, it is not fair for Duke to recover for the entire period of undercharges and that "on balance," it is fair and reasonable to apply Rule R8-44(4) and limit recovery to 150 days.

The Attorney General concedes that Commission Rules R8-9 through 14, which set standards for meter accuracy, testing, record keeping, and reporting, do not address the equipment that Duke now uses to read meters remotely. These rules were written long before these new devices were introduced, and it may be appropriate to consider standards for remote meter reading equipment. However, it is not clear that the application of reasonable standards would have caught the defect herein. It appears that the defect was rare and that it only affected "less than half a percent." Duke undertook random checks of the remote meter readings, but simply did not catch Complainant's situation because her meter was not one of those checked at random. Overall, Duke is getting better results from the remote-read meters than from its manual-read meters. Rule R8-44(4) addresses situations where undercharges result from a machine or meter error. Recovery in such cases is limited to 150 days "except as provided in (3) above," and the Hearing Examiner has already concluded that section (3) applies here. Therefore, the Attorney General is arguing, in the name of equity, for a result contrary to the provisions of Rule R8-44. The Hearing Examiner believes that the provisions of the Rule are clear and that the result produced by the Rule is fair and equitable. As Duke's witness testified, "[I]t's appropriate to ask Ms. Ray to pay for the usage that she has used just like those customers who reported similar malfunctions themselves have been billed for what they've used...." The Hearing Examiner finds no reason to deviate from Rule R8-44 as written.

The Hearing Examiner will, however, require that Duke work with Complainant as to payment arrangements. Duke offered to do so in its July 7, 2004 letter explaining the underbilling to Complainant, and a payment agreement was subsequently entered. That agreement was suspended pending this decision, but it should be reinstated now.

IT IS, THEREFORE, ORDERED that the complaint filed herein on November 15, 2004, should be, and the same hereby is, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of September, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah090705.10

DOCKET NO. E-2, SUB 868

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of 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 Rule R8-55	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, August 2, 2005, at 10:00 a.m., Tuesday, August 9, 2005, at 9:00 a.m., and Wednesday, August 10, 2005, at 9:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Jo Anne Sanford, Presiding; and Commissioners Robert V. Owens, Jr., and Sam J. Ervin, IV

APPEARANCES:

For the Applicant:

Len S. Anthony, Deputy General Counsel – Regulatory Affairs, Progress Energy Service Company, P.O. Box 1551, Raleigh, North Carolina 27602-1551

Dwight W. Allen, Smith, Anderson, Blount, Dorsett, Mitchell & Jernigan, P.O. Box 2611, Raleigh, North Carolina 27602-2611

For the Public Staff:

Antoinette R. Wike, Chief Counsel, and Robert S. Gillam, 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, N.C. Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Utility Customers Association, Inc.:

James P. West, West Law Office, P.C., Suite 1735, Two Hannover Square, 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

For the Carolina Industrial Group for Fair Utility Rates II:

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

For the Department of Defense:

Robert A. Ganton, Attorney, 901 North Stuart Street, Suite 525, Arlington, Virginia 22201

For the North Carolina Retail Merchants Association, Inc.:

T. John Policastro, P.O. Box 97713, Raleigh, North Carolina 27624-7713

For the North Carolina Electric Membership Corporation:

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

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 3, 2005, PEC filed its Application along with the testimony and exhibits of Company witnesses Ronnie M. Coats and Bruce P. Barkley. In its Application, the Company requested an increment of 0.880 cents/kWh (0.909 cents/kWh including gross receipts tax) to the base factor of 1.276 cents/kWh approved in PEC's last general rate case, Docket No. E-2, Sub 537, resulting in a recommended fuel factor of 2.156 cents/kWh. The Company also requested an increment of 0.296 cents/kWh (0.306 cents/kWh including gross receipts tax) for the Experience Modification Factor (EMF) to collect approximately $106.3 million of under-recovered fuel expense during the test period and the amount deferred in Docket No. E-2, Sub 784, now eligible for recovery. The Company proposed that the EMF rider be in effect for a fixed 12-month period.

On June 6, 2005, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed a petition to intervene. The Commission granted CIGFUR II's petition on June 7, 2005.

On June 7, 2005, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which the Commission granted on June 9, 2005.

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

On June 7, 2005, the Commission issued its Order Scheduling Hearing, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice. The Commission scheduled the hearing for August 2, 2005.

On June 27, 2005, the Attorney General filed a notice of intervention pursuant to G.S. 62-20.

On July 5, 2005, PEC submitted a joint motion, on behalf of CIGFUR, CUCA, the Public Staff, the Attorney General and itself, to alter the schedule for conducting discovery, filing testimony and holding the evidentiary hearing. The motion was granted by the Commission on July 7, 2005. The Commission set the August 2, 2005 hearing for public witness testimony only and scheduled a new hearing for August 9, 2005, for the testimony and cross-examination of witnesses by the parties.

On July 8, 2005, the United States Department of Defense (DOD) filed a petition to intervene, which the Commission granted on July 12, 2005.

On July 13, 2005, CUCA filed a motion to further alter the schedule for the filing of intervenor testimony. PEC filed its objection that same day, and the Commission subsequently denied the motion on July 15, 2005.

On July 18, 2005, the North Carolina Retail Merchants Association, Inc., filed a petition to intervene, which the Commission granted on July 20, 2005.

On July 19, 2005, North Carolina Electric Membership Corporation (NCEMC) filed a petition to intervene out of time. CUCA filed its objection on July 21, 2005, and amended it on July 22, 2005. The Commission subsequently granted NCEMC's petition on July 22, 2005.

On July 21, 2005, the North Carolina Eastern Municipal Power Agency and the Public Works Commission of the City of Fayetteville also filed petitions to intervene out of time. CUCA filed its objection on July 22, 2005. The Commission subsequently granted both petitions on July 22, 2005.

On July 25, 2005, CUCA filed the direct testimony of Kevin O'Donnell, and the DOD filed the direct testimony of Thomas J. Prisco.

On July 25, 2005, the Public Staff filed the direct testimony of Thomas S. Lam, the affidavit of Darleen P. Peedin, and a Settlement Agreement entered into by PEC, CIGFUR II, and the Public Staff. This agreement set forth the parties' resolution of all issues, including the appropriate adjustment to the base fuel factor and the EMF.

On July 28, 2005, PEC filed affidavits of publication showing that public notice had been given as required by Rule R8-55(f) and the Commission's June 7, 2005 Order.

At the hearing for public witnesses on August, 2, 2005, the following individuals testified: Bob Durand, Carrie H. Bolton, Margie Ellison, Herman Jaffe, Liz Cullington, Ivan Urlaub, Chris Witzgall, Pete MacDowell, Mary MacDowell, and Pat Regan. On August 9, 2005, Ms. Cullington submitted additional comments to clarify her testimony.

On August 3, 2005, PEC filed the rebuttal testimony of Ronnie M. Coats and Robert F. Caldwell.

The docket came on for hearing as ordered on August 9, 2005. No additional public witnesses appeared to testify. At the beginning of the hearing, counsel for all parties agreed to waive cross-examination of the Public Staff, DOD, and CUCA witnesses and to stipulate their testimony into the record. CUCA introduced the deposition transcripts and exhibits of R. Erik Hansen, Robert Caldwell, John Verderame, Paula Sims, Gary Freeman, and Racheal Shirk. PEC then presented witnesses Bruce P. Barkley and Ronnie M. Coats for cross-examination. Following their testimony, CUCA examined Randy Wilkerson, PEC's Director of Operations at the Energy Control Center, whom it had subpoenaed. PEC then presented rebuttal witness Robert

F. Caldwell for cross-examination.

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. 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, 2005.

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. The proper fuel factor for purposes of this proceeding is 1.775 cents/kWh, excluding gross receipts tax, or 1.834 cents/kWh, including gross receipts tax.

6. It is reasonable to apply a 60% fuel ratio to total energy 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 $87,662,142.

8. PEC should be allowed to recover $21,000,000 of the $55.46 million under-recovery deferred from Docket No. E-2, Sub 784 and 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.

9. The appropriate EMF increment to use in this proceeding is 0.303 cents/kWh (0.313 cents/kWh including gross receipts tax).

10. It is appropriate for PEC to implement a decrement rider of 0.007 cents/kWh (0.007 cents/kWh including gross receipts tax) to refund $2,431,000 to N.C. retail customers resulting from a settlement with the Staff of the Federal Energy Regulatory Commission (FERC) in a recent audit.

11. PEC's forecasted natural gas prices for the period October 1, 2005, through September 30, 2006, are reasonable.

12. The new maximum dependable capacity (MDC) value proposed by PEC for

Brunswick Unit No. 1 should be accepted.

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 which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for an historical 12-month period. In Commission Rule R8-55(b), the Commission has 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, 2005, 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, 2005.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding can be found in the Company's Application and the monthly fuel reports on file with the Commission, the testimony of Company witnesses Coats and Caldwell, the testimony of PEC employee Kenneth R. Wilkerson and Public Staff witness Lam, and the affidavit of Public Staff witness Peedin.

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 in the Fuel Procurement Practices Report which was updated in June 2005 and filed with the Commission on June 2, 2005, in Docket No. E-100, Sub 47A. 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 849 for calendar year 2004 and in Docket No. E-2, Sub 862 for calendar year 2005.

Company witness Coats described in detail the Company's coal and gas procurement practices. According to his testimony, the Company relies on short-term and long-term simulation models to estimate the coal and gas requirements at PEC's generating plants. Using this information in conjunction with plant inventory levels and supply risks, a determination is made of the coal requirements at that time. Once this determination is made, coal suppliers are contacted and asked to submit bids to meet the coal requirements. Coal contracts are awarded based on economic evaluation, supplier credit review, past performance, and coal specifications. Gas contracts follow more industry-recognized price indices and adders and are generally shorter term than coal contracts. During the test period, PEC's actual system requirement for coal was met at an average cost of $41.40/ton and PEC's actual system requirement for gas was met at an average cost of at $6.70/Dt, excluding transportation.

Witness Coats testified that PEC mitigates the impact of increasing fuel costs with a diverse mix of generating plant resources. He indicated that the Company's efficient use of nuclear, fossil-fueled, and hydroelectric plants helps lessen the impact of volatility in the price or supply of any one fuel source. This is illustrated by the fact that over 45% of PEC's generation during the test period was provided by nuclear plants at an average fuel cost of $0.41/mmBtu -- less than 20% of the fuel cost of coal generation and less than 5% of the fuel cost of natural gas generation. According to witness Coats, PEC has invested over $100 million on upgrades to its nuclear plants since 2001. These upgrades have allowed PEC to increase the capability of its nuclear fleet by about 300 MW, which not only avoided the need to install alternative capacity during this time but provided about 2.5 million MWh each year of additional nuclear generation in lieu of coal or natural gas.

Regarding the operation of PEC's coal fired plants, witness Coats explained that PEC had addressed fuel cost from both a transportation and fuel perspective. On the transportation side, PEC installed a barge unloading facility at its Sutton Plant in 2002. This facility provided an alternate transportation source for the Sutton Plant as well as access to foreign coal suppliers. Witness Coats indicated that the alternative transportation source provides competition for rail access to the plant and was instrumental in helping PEC maintain favorable rail transportation rates to the Sutton Plant and other plants served by the CSX railroad. The capability to receive coal from foreign suppliers also provides competition for the Central Appalachian (CAPP) coal suppliers that PEC has traditionally used.

Witness Coats also testified that PEC maintains a fleet of private rail cars for the transport of coal. The use of private cars allows PEC to take advantage of discounts from the shippers. In addition, these cars carry more coal per car than those provided by the railroads, and, thus, PEC can haul more coal per shipment. The private cars also have rapid discharge capability, which allows them to be unloaded faster and more safely than traditional rail cars, again providing a rate advantage and reduced O&M costs associated with fuel unloading. Witness Coats further explained that, in order to expand the use of private cars to all of PEC's facilities, PEC is making modifications to the track and coal unloading facilities at its plants. The final modifications are scheduled to be completed mid-2006. At that time, all PEC plants will be able to be served by private cars.

On the fuel side, witness Coats testified that PEC has developed processes that allow the Company to take advantage of "off-specification" coals that often become available in limited quantities but at much lower costs. An example would be a coal with a higher than desired ash content or a lower than desired heat content. Witness Coats indicated that, by working with the plants to develop the ability to receive such coals and blend them with the normal coals used at the plants, PEC has developed the ability to use such coals without adversely impacting plant operations. During 2004, PEC achieved fuel savings of about $3 million through the practice of using "off-specification" coals.

Regarding natural gas, witness Coats explained that in 2004 PEC acquired natural gas storage on the East Tennessee pipeline. This storage ultimately delivers into Transco Zone 5, where it is used to supply natural gas for PEC's fleet. Witness Coats testified that this acquisition allows PEC the opportunity to store natural gas to meet PEC's peaking needs for the same day and the next day. This affords PEC the opportunity to use storage gas instead of purchasing gas in the intraday market when prices are unusually high. This also allows PEC to fill storage when prices are lower, such as over the weekend. In addition, the supply can be utilized to insure reliability during hurricanes in the summer and wellhead freeze-offs and other disturbances during the winter. For example, if a hurricane shuts down production in the Gulf of Mexico supply area, PEC will be able to supply a portion of its natural gas requirements by pulling gas out of storage versus purchasing potentially higher priced supply from the market.

Witness Coats also testified that the fuel purchases made by PEC during the test year were necessary to ensure an adequate supply of fuel to meet its customers' electrical requirements during this period and that the fuel was secured at a reasonable cost utilizing prudent procurement practices and procedures. Witness Coats testified that the Company continuously evaluates the term and spot markets for coal, nuclear, oil, and natural gas in order to determine the appropriate portfolio of long-term and spot purchases of fuels that ensure a reliable supply of electricity to its customers at the lowest reasonable prices. Such evaluations include daily, weekly, and monthly solicitations, subscription to fuel pricing services and trade publications, and frequent discussions with fuel suppliers.

Witness Coats explained why PEC's coal costs have increased so significantly. Coats Exhibit No. 3 illustrates how the market price of CAPP coal has increased during the last 18 months. Market prices increased from the low $40/ton range at the beginning of 2004 to over $50/ton in April 2004, and to a peak of $65-$70/ton in the middle of 2004. Prices have fluctuated somewhat since then and as of May 2005 were in the range of $60/ton to $68/ton. Witness Coats testified that there are a number of factors causing this increase.

First, witness Coats indicated that production costs have increased. Labor, fuel, mining materials such as steel and explosives, and environmental costs have all increased, and overall mining costs are up 20% to 35% in the last 12 to 18 months. Secondly, the demand for coal in Asia, in particular China, has greatly increased. At the same time that demand has increased, CAPP coal supply is decreasing. Permitting difficulties have made it extremely difficult to boost production at existing mines or to open new mines. Lower cost coal reserves are being depleted, and more expensive coal is being mined to meet market demand. Several large Eastern coal producers experienced financial troubles and sought bankruptcy protection, thus reducing or terminating production at some of their mines as a means to lower production costs. In addition, the inability of these same producers to raise new capital to expand their operations resulted in higher cost coal. Finally, on a price-per-BTU basis, natural gas is still twice as expensive as coal. Thus, coal venders face no real commodity competition to put downward pressure on coal prices.

Despite this sudden and significant run-up in coal prices, witness Coats testified that the Company's overall coal costs for the April 2004 through March 2005 period were below prevailing market prices. This is illustrated in Coats Exhibit No. 4, which compares the historical spot market price curve with the price of spot coal deliveries during 2004 and early 2005. As this chart shows, even with constantly rising prices during the period of April 2004 through March 2005, PEC was successful in obtaining coal at less than market prices.

Public Staff witness Lam reviewed the Company's test period fuel prices and determined that they were reasonable. Public Staff witness Peedin reviewed the Company's Monthly Fuel

Reports and performed an investigation of the Company's fossil, nuclear, and purchased power fuel costs. No party offered any direct testimony contesting the Company's test period fuel procurement.

PEC witness Coats was questioned by the Attorney General and CUCA on the non-delivery of 1.3 million tons of contract coal during the test period. Witness Coats explained the reasons why the coal was not delivered and PEC was forced to replace the coal at spot prices. Witness Coats testified that PEC was prudent in its coal contracting, with about 90% of the Company's forecasted coal requirements under contract for the test period.

Witness Coats explained that several factors occurred during the test period that caused the supply and delivery disruptions that resulted in the shortfall of delivery of contract coal. During 2004, there were several factors that disrupted both the ability of the railroads to deliver coal and the ability of the mines in the CAPP region to supply coal. Flooding in West Virginia and Kentucky, especially during the late spring and late summer periods, impacted both mining operations and rail operations. The flooding limited production capability and washed out rail tracks at mine loadout facilities, which prevented trains from being loaded on schedule. The heavy rains also led to production stoppages due to roof falls and other adverse mining conditions. Additionally, several suppliers experienced financial difficulties which impacted their ability to meet production schedules. In addition, enforcement of stricter truck weight limits in West Virginia increased mining costs and production costs because the mines were required to haul fewer tons per truck. Increased mining and mine reclamation permit restrictions limited the ability of mines to expand or open new production areas. Finally, increased demand for export coal and other high revenue commodities led the railroads to allocate more resources to higher revenue producing operations. This led to a shortage of locomotive power, crews, and railcars to serve the domestic coal markets. All of these factors, acting together, disrupted deliveries for PEC as well as other users of CAPP coal.

Witness Coats testified that it is an industry practice to allow "make up" shipments from suppliers who are willing to satisfy their contractual obligations if they fall behind. Other remedies might include terminating the contract or litigation, but neither of these remedies are productive because what PEC needs and wants is the coal. In addition, there would be significant time and costs associated with any potential legal remedy related to supplier contract defaults with no guarantee of success. According to witness Coats, since utilities are currently in a seller's market, it is very difficult to include substantial liquidated damage language in coal contracts. The sellers will simply take their coal elsewhere.

Witness Coats testified that PEC evaluated each contract and determined appropriate corrective action. The causes of missed shipments included supplier failure to load, force majeure, and poor railroad performance. In most cases where the contracted volume was not shipped, the primary cause was difficulties with railroad scheduling (i.e., rationing of permits) and reliability of railroad performance due to shortage of locomotive power, equipment, and crews. Witness Coats testified that PEC had contacted the delinquent suppliers and had made arrangements to obtain the majority of the coal short-fall from these suppliers at the contract prices. He further explained that, of the 1.3 million tons of coal that were not delivered on schedule, only a small percentage could, at this time, be considered unjustifiable non-performance. He also testified that, in a limited number of cases due to reduced reliability of railroad performance, the volume was not contractually required to be made up. Finally, witness

Coats explained that some of these cases remain in dispute and the Company is uncertain at this time whether or not it will receive all tons not shipped during the test period.

Witness Coats testified that PEC continues to enter into long-term contracts at prices below the current market price for coal.

In his brief, the Attorney General takes the position that PEC was imprudent for failing to enter into coal supply contracts for 100% of the coal which PEC projected it would need during the test year. More specifically, the Attorney General recommends that PEC's requested under-recovery of test year fuel costs be reduced by $17,765,000, which is the additional amount that the Attorney General calculates that PEC had to pay to obtain the coal which it needed during the test year on the spot market.

The Attorney General notes that PEC projected it would need 11.6 million tons of coal during the test year. Prior to the test year, PEC had entered into coal supply contracts for 10.5 million tons, or approximately 90% of the coal which PEC projected it would need. This was consistent with PEC's practice prior to the test year, which was to enter into coal supply contracts with terms of up to three years in duration for delivery of between 70% to 90% of its projected needs for the next test period. PEC planned to purchase the remaining 1.1 million tons, or 10% of its projected needs, at spot market prices. According to the Attorney General, the price of the 10.5 million tons under contract was $34.18/ton and the delivered price, including transportation, was $48.60/ton. However, during the test period PEC actually used 12.1 million tons of coal. Since PEC used 1.6 million more tons of coal than it had under contract and because several of PEC's suppliers defaulted on about 1.2 million tons of coal under contract, PEC actually purchased about 2.8 million tons of coal on the spot market during the test year. The price of the coal purchased on the spot market was $49.11/ton and the delivered price, including transportation, was $64.75/ton.

In support of its position, the Attorney General argues in its brief that PEC should have contracted for 100% of its projected coal needs prior to the test period based on the previous and continuing rise in coal prices, as well as underlying market conditions, and projected lack of any near-term relief. For example, the Attorney General cites the testimony and exhibits of PEC witness Coats, which indicate that CAPP coal prices ranged from approximately $30/ton in January of 2003 and increased above $35/ton in August or September of 2003. By the end of December of 2003, coal prices were approximately $40/ton. At the end of March of 2004, which is the beginning of the test period in this proceeding, coal prices were in the range of approximately $55/ton to $58/ton. PEC witness Coats testified that the underlying reasons for the price increases included increased production costs, increased foreign demand, decreasing CAPP supply, financial difficulties experienced by coal suppliers, and the absence of real commodity competition to put downward pressure on prices. The Attorney General states such market conditions did not occur over a short period and they were not market conditions that would be expected to last for a short period. The Attorney General further states that there was no reasonable prospect of relief since 60% of the CAPP coal suppliers, including a supplier of PEC, were in bankruptcy. The Attorney General adds that PEC typically uses about the same amount of coal each year, ranging from 11.6 million tons to 11.9 million tons per year in the last three years. Although PEC witness Coats was not able to state the amount of PEC's coal storage capacity, the Attorney General opines that PEC has no shortage of coal storage capacity and any coal not used within a year will be used shortly by PEC. Finally, the Attorney General points out that PEC witness Coats testified that, in response to drastic changes in the coal market in early 2004, PEC recently changed its coal purchasing inventory target range to acquire 95% to 115% of its projected needs under contract and to extend the terms of the contract to four years or more.

In considering the position of the Attorney General that PEC's failure to enter into coal supply contracts prior to the test year for the remaining 10% of its projected need for coal was imprudent, the Commission first notes that no witness in this proceeding challenged PEC's coal purchasing practices. To the contrary, Public Staff witness Lam testified that his review of test period fuel costs found them to be reasonable and prudent. In addition, the Commission does not discount the significance of the fact that PEC already had approximately 90% of its projected need for coal during the test period under contract prior to the beginning of the test period. The testimony of PEC witness Coats reveals that 90% was at the upper end of the 70% to 90% coal inventory target range contained in PEC's coal purchasing practices at that time.

The Attorney General argues that PEC should and could have contracted for the remaining 10% of its projected need for coal at a delivered price of $48.60/ton prior to the beginning of the test period. However, the Attorney General cites no convincing or compelling evidence as to whether a sufficient quantity and quality of coal was available for contract from a reliable supplier which could have been transported and stored when needed by PEC at a delivered price of $48.60/ton. Considering only coal prices, PEC Coats Exhibit No. 3 illustrates how the CAPP market prices of coal increased from the beginning of 2003 through the beginning of the test period in April of 2004. Obviously, purchases of coal during the earlier months shown on the graph were or could have been made at contract prices which were lower than purchases during the later months, but that observation can only be made through hindsight and prudency should not be judged through hindsight. Further, even if PEC had managed to enter contracts prior to the beginning of the test year for the remaining 10% of its projected need for coal at a delivered price of approximately $48.60/ton, PEC would have lost the flexibility to forego the cost of some of that coal if the actual need for coal was less than the projected need, or to perhaps purchase coal at even a lower cost on the spot market if spot market prices subsequently declined.

Based upon the preponderance of evidence, the Commission simply disagrees with the Attorney General that PEC was imprudent for failure to purchase 100% of its need for coal prior to the test period. Instead, the Commission concludes that PEC's coal purchasing practices during the test period were reasonable and prudent based upon the evidence in this proceeding.

CUCA raised an issue during its cross-examination of PEC witness Coats concerning why PEC did not engage in hedging for its natural gas purchases for the test year. In its brief, CUCA requested the Commission to disallow $13.8 million of PEC's natural gas fuel costs incurred during the test year as imprudent due to PEC's failure to hedge its natural gas purchases.

In support of its position, CUCA notes that PEC witness Coats acknowledged the volatility of natural gas prices. Given such an environment, CUCA believes that PEC would be expected to financially hedge its natural gas purchases to provide price stability. CUCA also points out that two of PEC's affiliates, Progress Energy Florida (PEF), a regulated utility operating in Florida, and Progress Ventures (PV), an unregulated marketing affiliate, have engaged in hedging of their natural gas purchases. In addition, CUCA cites that North Carolina Natural Gas Corporation accepted a disallowance of approximately $450,000 in Docket No. G-21, Sub 450, a gas cost prudency review in 2004, for its failure to hedge its natural gas purchases. CUCA also introduced CUCA Coats Cross-Examination Exhibit No. 2, which was an internal document of PEC from 2001 containing the statement that "since fuel is passed through to ratepayers via annual rates, there are no regulatory or business reasons to hedge or enter into forward price transactions."

During cross-examination, no PEC witness knew the context of the 2001 document or the department or person involved in creating the document. Further, PEC witness Coats testified that in 2001, PEC's gas-fired generation consisted of combustion turbine units that only ran a few hours per year in order to meet peak load demand. At that time, he testified that there was no reason to hedge given the combination of the difficulty in forecasting how much or when natural gas would be needed and the low volumes consumed. Witness Coats further testified that, in 2003, PEC added its first and only combined cycle gas-fired unit and that until 2005 PEC has needed relatively small amounts of base load natural gas. He went on to explain that PEC's projected needs for natural gas have continued to increase and, therefore, that PEC intends to implement a hedging strategy this year of "buying through the (pricing) curve" for the high volume months of January, June, July, and August. He further explained that PEC expects to use various hedging products such as fixed price supplies, zero cost dollars, etc., to stabilize price volatility for up to five years for those months. Witness Coats was generally not familiar with the hedging of PEF or PV or whether the hedging at these affiliates was successful. However, according to his testimony, PEF purchased considerably more natural gas than PEC and the minimum monthly demand for PEF was greater than the maximum monthly for PEC over the last 12 months. In addition, while he acknowledged that PV hedged a relatively small quantity of natural gas, he maintained that PV operates in a totally different environment.

In considering this issue, the Commission notes at the outset that no witness to this proceeding, including CUCA's own witness who did not mention hedging, testified that PEC was imprudent for failing to use financial hedging for natural gas during the test period. Public Staff witness Lam testified that he had reviewed the Company's fuel costs for the test period and found them to be reasonable and prudent. Concerning the natural gas price hedging used by PEF and PV, but not by PEC during the test period, there is insufficient or no compelling and convincing evidence to demonstrate that the use of natural gas by PEF or PV is sufficiently similar to PEC's use of natural gas during the test period, considering both volumes and projected usage patterns of these entities, to demonstrate that PEC should have engaged in such hedging during the test period. The Commission believes that CUCA Coats Cross Examination Exhibit No. 2 should be viewed in the context of the operating circumstances that existed in 2001, several years prior to the test period in this proceeding. The testimony of witness Coats explains that there were legitimate reasons for PEC not to engage in hedging prior to 2005. The Commission also notes that PEC now owns and operates a combined cycle natural gas-fired generator and is forecasting a significant amount of gas for base load generation purposes. Therefore, PEC intends to utilize hedging tools to stabilize its natural gas costs.

At CUCA's request, the Commission has taken judicial notice of Docket No. G-100, Sub 84, a proceeding initiated by the Commission in 2001 to raise and address issues concerning the hedging of commodity costs by natural gas local distribution companies (LDCs), and Docket No. G-21, Sub 450, an annual gas cost review proceeding for PEC's former subsidiary North

Carolina Natural Gas Corporation. As these dockets indicate, the use of hedging tools, including financial tools, to stabilize commodity prices has become an increasingly acceptable and even expected practice for the state's LDCs, which have long engaged in various kinds of physical hedging. The Commission amended Rule R1-17(k)(2)(b) in Docket No. G-100, Sub 84, to include in the definition of "Gas Costs" recoverable under G.S. 62-133.4 "all direct, transaction-related costs arising from an LDC's prudent efforts to stabilize or hedge commodity gas costs." This amendment reflects the Commission's understanding that the purpose of hedging by the LDCs is to mitigate price volatility, not to minimize gas costs, and that the use of financial hedging tools, even when prudent, may result in an increase in gas costs over the long term. Nevertheless, because changes in the commodity cost of gas are passed through to customers as often as monthly, the Commission believes hedging to be an appropriate business and regulatory tool for the LDCs to use.

The effects of volatility and upward movement in natural gas prices on PEC and its customers are clearly distinguishable from those experienced by the LDCs and their customers. PEC purchases natural gas for use as a fuel to generate electricity, not as a commodity for resale to its customers. Natural gas is only one of several fuels relied upon by PEC to generate electricity to meet the needs of its customers. As explained by witness Coats, PEC's use of natural gas as a fuel has only recently reached a level of volume and degree of predictability to justify some kind of hedging. In the meantime, under G.S. 62-133.2, PEC is permitted to recover changes in its fuel costs only once a year.

The Commission wishes to remind the Company that it has an obligation to minimize its fuel costs and, when appropriate, to stabilize its natural gas costs during periods of price volatility. Therefore, while the Commission is inclined to look favorably on PEC's decision to add hedging to its gas procurement practices in 2005, the Commission does not find that PEC should have engaged in hedging during the test period. Further, the Commission concludes that PEC's gas purchasing practices were reasonable during the test period.

In its brief, CUCA posited that because PEC has traditionally been allowed to recover in fuel clause proceedings only part of its purchased power costs from sellers who did not provide PEC the actual fuel cost associated with such purchases, PEC may have refrained from engaging in power purchases unless the savings to be realized from such purchases were substantial. More specifically, CUCA recommends that the Commission disallow $36.2 million of PEC's test period fuel costs because CUCA believes that PEC has failed to purchase appropriate amounts of energy from third parties.

The Commission allowed CUCA to subpoena the Manager of PEC's Energy Control Center, Kenneth R. Wilkerson, to appear as a witness in this proceeding to address the Energy Control Center's practices. The crux of CUCA's arguments relates to a memo dated September 5, 2001, and prepared by the department head responsible for PEC's Bulk Power Trading Department at that time, and an associated exchange of e-mail, which CUCA introduced as CUCA Wilkerson Direct Examination Exhibit No. 2. Using this exhibit, CUCA attempted to show that PEC's Energy Control Center, which makes the final decision as to whether PEC will make a power purchase to displace Company-owned generation, could have been using a savings threshold of 40% when making purchased power decisions because of the marketer stipulation.

Witness Wilkerson testified that the dispatch group at the Energy Control Center in 2001 and 2002 performed two tests or "screens" on each purchase: an economic screen and a reliability screen. Purchases that passed both screens were executed and made available to serve native load customers. Witness Wilkerson testified that PEC's dispatchers are trained to make the least cost decision when serving customers, whether it be by dispatching generation or by executing purchases.

Witness Wilkerson further testified that the Energy Control Center has never utilized any type of fixed savings threshold in deciding whether to make a power purchase to displace Company-owned generation. Rather, witness Wilkerson said that, during his entire tenure as Manager of the Energy Control Center, which began in 1997, the Energy Control Center has always made power purchases whenever a purchase was economic and sufficiently reliable for the Company to depend upon it to meet the needs of its customers rather than using Company-owned generation. Witness Wilkerson indicated that, when he received the 2001 memo and e-mail introduced by CUCA, he was quite upset because they misrepresented the practices of the Energy Control Center. He acknowledged that, in hindsight, he possibly should have responded to the author of the memo and corrected the author's misunderstandings. However, since the Energy Control Center ultimately makes the final decision as to whether a purchase should be made, the author's understanding of its practices had no impact on the purchasing decisions made by the Energy Control Center. In addition, any possible need to address any misunderstanding was eliminated when the department head in question was replaced by PEC witness Robert Caldwell in January 2002.

PEC presented Robert Caldwell, the Vice President of PEC's Regulated Commercial Operations Group, which includes the power trading operations, since January 2002, to address this issue. PEC witness Caldwell testified that, since he has been the Vice President in charge of PEC's power trading operations, his group has never employed any type of fixed savings threshold in deciding whether to recommend to the Energy Control Center that a power purchase be made. Both witness Wilkerson and witness Caldwell testified that, beginning sometime in 2003, the energy traders stopped providing any pricing information whatsoever to the Energy Control Center to assure compliance with the Federal Energy Regulatory Commission's Standards of Conduct. Thus, since that time, and particularly during the test period, the Energy Control Center did not possess the information that would have been required for it to determine the savings associated with any power purchase recommended by the energy traders. As a result, there is no convincing evidence that PEC forewent any reliable power purchases during the test period that were economic and could have reduced PEC's fuel cost.

CUCA introduced CUCA Caldwell Cross Examination Exhibit No. 1, a memo dated August 6, 2002, from a manager of the Power Trading Group to that department. In the memo, the author states, "We are expected to purchase power for our customers, without regard to the fuel/non-fuel split, when a purchase has a clear and distinct savings over our own generation cost or has a distinct operational or reliability advantage to our system." CUCA contrasted this memo with the statements of witness Caldwell that there was no reason for his traders to be made aware of the marketer stipulation and that he had never indicated to his employees that a purchase had to have a "clear and distinct savings" over Company-owned generation before the purchase should be made. Witness Caldwell was not the author of the memo.

Witness Caldwell indicated on cross-examination that there was no reason for his traders to be made aware of the marketer stipulation and that he had never indicated to his employees that a purchase had to have a "clear and distinct savings" over Company-owned generation before the purchase should be made, contrary to the August 2002 memo. Witness Caldwell testified that he saw no reason for his traders to be made aware of the marketer stipulation because they should not consider the marketer stipulation in determining whether to recommend a power purchase to the Energy Control Center. With regard to witness Caldwell's statement that he had never established a requirement that a power purchase have a "clear and distinct savings" over Company-owned generation, the context of the cross examination on this subject began with CUCA's attorney asking witness Caldwell whether his group had ever used a 40% savings threshold, or a 5% savings threshold, or whether anyone had ever required that savings be clear and distinct. Witness Caldwell's consistent testimony, as well as that of witness Wilkerson, was that there had never been any fixed savings thresholds employed by the Energy Control Center or the power trading group since witness Caldwell had been responsible for this area of the Company. Witness Caldwell explained that the use of the phrase "clear and distinct savings" in the memo could easily be interpreted as referring to all of the reliability issues that need to be taken into consideration when looking at a purchase.

Witness Caldwell also testified that the decision to purchase power is made several hours prior to the actual purchase. As a result, at the time the purchase occurs, it is possible that PEC's self-generation cost may have increased or decreased. Thus, it is not known until after the fact whether the purchase truly saved the Company any money. Therefore, it is reasonable and prudent for the Company to adopt a practice that, at the time the decision is made to make a purchase, the forecasted savings should be relatively certain.

In its brief, CUCA also argues that PEC eliminated the inclusion of variable operation and maintenance costs from the price list on which traders rely to decide whether to purchase energy from off-system suppliers. This argument was largely predicated upon the deposition testimony of Rachael Shirk, a PEC trader, who responded to a question from CUCA counsel by saying, "I don't believe our operating and maintenance is included in that [the price lists] anymore, O and M." However, after reviewing the entire deposition of Ms. Shirk, as well as all other evidence related to price lists, the Commission does not accept CUCA's argument that operating and maintenance costs were excluded from price lists used during the test period for the purpose of reducing power purchases.[1] Further, the Commission notes that the price list was not the only factor which was reasonably considered by PEC in making purchase decisions; actual, real-time operational data and reliability also factor into all such decisions.

Finally, CUCA argues in its brief that the annual savings target that must be achieved in order for PEC's traders to receive their full incentive pay creates an incentive for the traders to wait for purchase opportunities that offer the largest savings, and to forego purchases to displace Company-owned generation when the savings margin is relatively small. CUCA analogizes to a police chief who expects his officers to ticket a certain amount of total speeding per year, and thereby encourages them to let minor speeders go lest they miss an opportunity to catch a faster speeder. The Commission finds no evidence that the traders' incentive pay program is having such an effect. Further, the Commission does not believe that CUCA's argument follows logically: given that the number of opportunities to achieve savings in a year is limited and that the traders do not know when or what opportunities will arise, it would seem that the traders have an incentive to take advantage of every opportunity that might offer any savings in order to reach their overall annual goal.

[1] The Commission notes that PEC's reply brief relies upon a discovery response relating to Ms. Shirk's deposition that was not introduced into evidence at the hearing. In reaching its decision concerning the purchased power issue raised by CUCA, the Commission has not considered this discovery response.

While the Commission has focused on the test period in reaching its decision in this proceeding, it does have questions as to why the author of the 2001 memo and e-mail was under the impression that the Energy Control Center was using a savings threshold in evaluating power purchases. However, the evidence of record indicates that, since sometime in 2003, the Energy Control Center could not have employed a savings threshold because the hourly traders were not permitted to provide purchased power prices to the Energy Control Center.[1] In addition, it is the sworn and unimpeached testimony of PEC witness Wilkerson, who has managed the Energy Control Center since 1997, that no savings threshold has ever been used. Therefore, the Commission is not persuaded that, during the test period, PEC forewent purchasing power on the wholesale market to displace higher cost PEC-owned generation.

The testimony and evidence presented by PEC demonstrates that PEC, at least since January 2002, has not used any fixed savings threshold with regard to the decision to make power purchases. Since PEC presented persuasive evidence that its fuel procurement procedures and power purchasing practices were reasonable and prudent, and since no party offered any testimony or convincing cross-examination contesting the Company's test period fuel procurement and purchased power costs, the Commission finds and concludes that PEC's fuel procurement procedures and power purchasing practices were reasonable and prudent during the test period.

However, the Commission takes this opportunity to remind PEC and all electric utilities subject to the Commission's jurisdiction of their obligation to purchase reliable power to displace higher cost Company-owned generation whenever the opportunity arises to do so. Although the Commission has concluded that the evidence does not support CUCA's contentions that there were improprieties in PEC's purchasing practices during the test period, the hearing has shed new light on this important area of the Company's operations. As a public utility, PEC has an obligation to engage in energy purchases with the goal of lowering costs to ratepayers, and such practices should be an important part of PEC's overall strategy for the operation and dispatch of its generation fleet. Such purchases and practices are a legitimate subject of inquiry in fuel charge adjustment proceedings, and our decision herein should not be seen as foreclosing such inquiries in future proceedings.

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[1] CUCA raised questions as to whether pricing information was provided by the traders to the Energy Control Center subsequent to 2003 based upon certain language in the Federal Energy Regulatory Commission's Audit Report regarding Progress Energy's compliance with FERC's Standards of Conduct and Codes of Conduct. As explained at the hearing and as stated in the Audit Report, the time period audited by the FERC was January 2002 through October 31, 2003. Thus, to the extent the pricing information referred to in the report was provided by the traders to the Energy Control Center during this time, the Report is entirely consistent with PEC's testimony. However, it appears that, in addition to listening to recordings of telephone calls that occurred during the time period audited, the FERC also listened to some live calls that occurred during the time period November 2003 to December 2004. To the extent the pricing information referred to in the Report was conveyed during this time period, it would appear the Report is inconsistent with the testimony of PEC witnesses Caldwell and Wilkerson, both of whom testified under oath that, some time in 2003, the traders stopped providing pricing information to the Energy Control Center. In any event, there is no evidence as to when the pricing information referred to in the Report was actually conveyed, and the Commission does not find persuasive the mere possibility that such information might have been improperly provided.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding can be found in the Company's Application and in the direct testimony and exhibits of PEC witnesses Coats and Barkley and Public Staff witness Lam.

Witness Coats testified that PEC uses two different measures to evaluate the performance of its generating facilities. They are the equivalent availability factor and the capacity factor. Equivalent availability factor refers to the percent of a given time period that a facility was available to operate at full power if needed. 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. Equivalent availability factor describes how well a facility was operated, even in cases where the unit was used in a load following application.

The Company files with this Commission monthly Fuel Reports pursuant to Rule R8-52 and Base Load Power Plant Performance Reports pursuant to Rule R8-53. These reports were filed in Docket No. E-2, Sub 849 for calendar year 2004 and Docket No. E-2, Sub 862 for calendar year 2005. Witness Coats testified that the Company met the standard for prudent operation as set forth in Commission Rule R8-55(i) during the test period based upon the test year actual nuclear capacity factor of 93% exceeding the North American Reliability Council (NERC) five-year average (1999-2003 period) of 88.3%. The Company's Boiling Water Reactors (BWRs) at Brunswick 1 and 2 experienced capacity factors of 102.3% and 88.8%, respectively. The Pressurized Water Reactor (PWRs) at Robinson 2 and Harris 1 experienced capacity factors of 92% and 88.6%, respectively. Public Staff witness Lam verified the Company's test year average capacity factor calculation.

Commission Rule R8-55 provides that if a utility's nuclear generation performance exceeds the most recent five-year NERC average, there is a rebuttable presumption of prudent operation. PEC exceeded the applicable NERC average, and the Commission agrees with witness Coats that PEC prudently operated its nuclear generation during the test period.

Witness Coats testified that PEC's coal plants achieved an equivalent availability of 92.5% during the test period. The five-year NERC average equivalent availability for coal plants (all size ranges) was 84.14%, indicating excellent performance of PEC's coal plants relative to this performance indicator. PEC's combustion turbine units achieved a system average equivalent availability of 89.5% versus a five-year NERC average of 88%. Witness Coats asserted that, overall, these performance statistics indicate that PEC's generating fleet was prudently managed and operated.

In its post-hearing brief, CUCA seeks a disallowance for imprudent dispatch of PEC's generation fleet. CUCA cites Barkley Cross Examination Exhibit 5, a study comparing, month by month, PEC's actual production costs with its forecasted optimal costs. CUCA points to a 2.37% disparity between actual costs and forecasted optimal costs (a difference of $1,055,000) for the month of May 2004. CUCA argues that PEC failed to adequately explain the disparity and, therefore, that it failed to carry its burden of proof as to the prudence of the fuel costs for May 2004. CUCA concludes that this disparity reflects imprudent dispatch and seeks a disallowance equal to 85% of $1,055,000, reasoning that 85% of PEC's production costs were fuel costs. PEC responds that the forecasted optimal costs are based upon forecasts as to load, generator availability, and fuel costs and that if any of these forecasts are off for any reason, there will be a disparity between the forecasted optimal costs and actual costs. PEC witness Barkley could not explain the disparity for May 2004, stating that "this would require a lot of expertise from somebody that knows the details of running the system...." The Commission finds sufficient evidence, as summarized above, tending to show prudent management of the generation fleet for the test year. The disparity between forecasted and actual costs for one month, without more, does not tend to show imprudence and does not support a disallowance. See Utilities Commission v. Intervenor Residents, 305 NC 62, 75-6 (1982). Such a disparity may have been caused by any number of factors.

Based on the evidence, the Commission finds and concludes that the operation of the Company's base load plants was 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 Coats, the testimony of DOD witness Prisco, the testimony of Public Staff witness Lam, the affidavit of Public Staff witness Peedin, and the Settlement Agreement entered into by PEC, the Public Staff, and CIGFUR II.

In Barkley Exhibit No. 3, the Company calculated a fuel factor of 1.898 cents/kWh based on normalized capacity factors for its nuclear units in accordance with Commission Rule R8-55(c)(1), using the five-year NERC Equivalent Availability Report 1999-2003 average for BWRs and PWRs. The workpapers included in Barkley Exhibit No. 7 show kWh normalization for customer growth and weather at both meter and generation levels and was performed in a manner consistent with that used in 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 that used in past cases. The NERC five-year capacity factors for Brunswick Unit Nos. 1 and 2, both BWRs, were normalized at 88.7%, and the capacity factors of the Robinson and Harris Units, both PWRs, were normalized at 87.9%. The Company's NERC normalized calculations resulted in a system nuclear capacity factor of 88.3% using this data.

Witness Barkley explained in his pre-filed testimony the importance of matching fuel cost with fuel revenues during the time period that rates are in effect; thus he could not recommend the 1.898 cents/kWh fuel factor developed based on the NERC average capacity factors and historical test period data. Witness Barkley expressed concern that the 1.898 cents/kWh fuel factor would cause PEC to under-recover its fuel costs during the time period that rates approved in this proceeding are in effect despite the fact that the nuclear units are forecast to exceed the 88% NERC average during the projected period. Witness Coats testified that the coal market began to climb in late 2003, driven primarily by increased mining costs, high demand for coal from foreign markets, and depletion of low cost coal reserves. He testified that market coal prices will be higher during the time period that rates will be in effect than they were during the test period. Witness Coats also testified that gas prices will be higher in the rate recovery period than what was experienced during the test period.

Company witness Barkley recommended a base fuel factor of 2.156 cents/kWh based on projected costs during the time period that rates established in this case will be in effect. Witness Barkley explained that this fuel factor is based on a nuclear capacity factor of 93% expected during the rate recovery period along with updated fuel cost projections. This calculation is shown on Barkley Exhibit No. 3A, which was included with his direct testimony. The computation of the 2.156 cents/kWh factor is summarized below:

Generation Type	MWhs	Fuel Cost
Nuclear	28,226,760	$127,725,486
Purchases – Cogen	1,769,000	51,373,100
Purchases – AEP Rockport	1,911,800	25,331,300
Purchases- Broad River	329,200	36,446,200
Purchases-SEPA	182,000	0
Purchases-Other	150,100	4,424,200
Hydro	747,000	0
Coal	31,329,000	937,845,100
IC & CC	2,338,000	217,142,200
Sales	(2,812,000)	(114,744,900)
Total Adjusted	64,170,860	$1,285,542,686
Less NCEMPA:		
PA Nuclear	3,584,880	$17,294,600
PA Buy-Back & Surplus	(394,563)	(2,212,500)
PA Coal	1,230,011	38,610,800
System Projected Fuel Expense		$1,231,849,786
Projected kWh meter sales		57,147,787,300
Projected Fuel Factor (cents/kWh)		2.156

DOD witness Prisco testified that the Commission should phase-in the increase in the fuel factor since the total increase recommended by PEC is a significant amount. Witness Prisco stated that the DOD budgets at the military installations served by PEC could not absorb the increase recommended by PEC without placing a financial strain on their facility resources. Witness Prisco proposed a base fuel factor of 1.791 cents/kWh without a basis for the factor other than a phased increase over two years.

According to the testimony of Public Staff witness Lam, after review of the Company's Application, he 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 projected nuclear capacity factors and the reasonableness of PEC's proposed coal costs during the rate recovery period. However, in order to mitigate the rate impact to PEC's customers, witness Lam endorsed a fuel factor of 1.775 cents/kWh, excluding gross receipts tax, as agreed to in the joint Settlement Agreement of the Public Staff, CIGFUR II, and the Company.

On July 25, 2005, the Public Staff filed the Settlement Agreement (Agreement) entered into by PEC, CIGFUR II, and the Public Staff. At the hearing, PEC witness Barkley sponsored the Agreement as Barkley Exhibit No. 9. In the Agreement, the parties to the Agreement agree to adjust the base fuel factor established in PEC's last general rate case by 0.499 cents/kWh (0.516 cents/kWh including gross receipts tax[1]), resulting in a base fuel factor of 1.775 (1.276 + 0.499) cents/kWh. The Commission notes that this fuel factor is lower than the factor suggested by DOD witness Prisco. The parties also agree that PEC should be allowed to charge an EMF increment of 0.303 cents per kWh (0.313 cents per kWh including gross receipt tax) effective October 1, 2005, through September 30, 2006. Neither the Attorney General nor CUCA directly challenged the appropriateness of the 1.775 cents/kWh factor agreed to in the Agreement.

In recognition of the fact that a base fuel factor of 1.775 cents/kWh will, in all probability, cause PEC to significantly under-recover its fuel costs during the time period that the rate will be in effect, the Agreement provides that PEC shall be allowed to charge and collect interest at the rate of 6%, compounded annually, on any under-recovery of fuel costs that occurs during the time period October 1, 2005, through September 30, 2006, that results from increasing the base fuel factor by 0.499 cents per kWh instead of 0.880 cents per kWh excluding gross receipts tax, as proposed in its Application, until all such costs have been recovered.

The evidence of record would support approval of a base fuel factor of 2.156 cents/kWh effective as of the date of this Order. However, having reviewed the testimony of the witnesses of PEC and the Public Staff, as well as of the public witnesses in this proceeding, the Commission finds merit in the phase-in approach set forth in the Agreement. It significantly mitigates the near term impact to PEC's customers of the increasing costs of coal, natural gas, and rail transportation, and the Commission believes that adopting the Agreement is in the public interest. The Commission concludes that the 1.775 cents/kWh base fuel factor set forth in the Agreement is reasonable and appropriate and should be approved.

CUCA challenges the Agreement on two grounds. First, CUCA argues that the Agreement fails to disallow any of PEC's fuel costs. The Commission has carefully considered all of the challenges to PEC's proposed fuel factor and has discussed the evidence and the Commission's conclusions with respect to those issues in this Order. The decision not to disallow any fuel costs is based upon the reasons discussed. Second, CUCA challenges the interest provision of the Agreement. CUCA argues that electric utilities have not previously been allowed to collect interest on test period under-recoveries. PEC cites Docket No. E-2, Sub 784, its 2001 fuel charge adjustment proceeding, in which the Commission approved a stipulation by all the parties except the Attorney General which provided for accrual of interest on an uncollected EMF amount that was deferred for recovery for 5 years in order to spread out the rate impact. CUCA distinguishes the Sub 784 proceeding because it dealt with the EMF factor, not the fuel factor, and further argues that its agreement in that proceeding does not create any precedent for this proceeding. CUCA also argues that the collection of interest "does not appear to be lawful": CUCA cites G.S. 62-130(e) and Rule R8-55(c)(5), both of which require the Commission to include interest when it orders a utility to refund money that was advanced to or overcollected by the utility. The Commission notes that neither the statute nor the Rule is directly on point because they both deal with interest on refunds and neither addresses the

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[1] The Settlement Agreement filed by PEC, the Public Staff, and CIGFUR II on July 25, 2005 indicated that the increase to the base fuel factor including gross receipts tax was 0.515 cents/kWh. However, as part of the Public Staff's and PEC's Joint Proposed Order, they submitted a revised Settlement Agreement on September 6, 2005, correcting the increase including gross receipts tax to 0.516 cents/kWh. PEC also filed a revised copy of the Settlement Agreement along with its reply brief on September 12, 2005, correcting a clerical error.

accrual of interest on under-recoveries. The Commission concludes that the interest provision of the Agreement should be approved because PEC is foregoing revenues that it is otherwise entitled to collect in rates during the upcoming year. According to the evidence herein, PEC is entitled to recover the full amount requested in its Application through rates that would take effect on October 1, 2005. The Commission will defer recovery of a portion of that amount in order to minimize the immediate impact on ratepayers; however, it is necessary to providé for the accrual of interest in connection with the deferral in order to make PEC whole. The Commission believes that G.S. 62-30, 62-31, 62-32, and 62-130 grant sufficiently broad powers to authorize the interest provision of the Agreement. The Commission will allow PEC to accrue interest in accordance with the Agreement, at an annual rate of 6%, compounded annually. PEC will be allowed to collect this interest in the EMF approved in future fuel cases, as the amounts of principal and interest to be collected become known.

G.S. 62-133.2(d) provides

> The Commission shall incorporate in its fuel cost determination under this subsection the experienced overrecovery or underrecovery 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 overrecovery or underrecovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case . . .

In the pre-filed testimony and exhibits submitted by Company witness Barkley, he requested recovery of $106,337,074 of under-recovered fuel expense consisting of three components. One component is the test period under-recovery of $87,768,074 using the base fuel factors approved by the Commission in Dockets No. E-2, Sub 833 and 851. This amount had been adjusted for the new marketer stipulation percentage proposed for this proceeding. The second component is $21,000,000 of the $55.46 million that was deferred in Docket No. E-2, Sub 784. The third component is a credit of $2,431,000 resulting from a settlement with FERC Staff over an audit of the Company's Code of Conduct and Standards of Conduct compliance. The Company requested an EMF increment of 0.296 cents/kWh (0.306 cents/kWh including gross receipts tax) to recover the full $106,337,074 amount of under-recovered fuel cost.

Public Staff witness Peedin reviewed the Company's calculation of the EMF for the test period. Witness Peedin recommended adjustments to the Company's marketer stipulation adjustment totaling $105,932. The Public Staff also recommended that the FERC refund component be removed from the EMF and that this factor be shown as a separate rider in the Company's rates. Witness Peedin calculated an EMF factor of 0.303 cents/kWh by dividing the under-recovery amount of $108,662,142 by 35,905,209,726 kWh. Witness Peedin also calculated the FERC refund factor of 0.007 cents/kWh by dividing the $2,431,000 refund amount by the same adjusted retail kWh.

For purposes of this proceeding, witness Peedin recommended that the Commission accept the application of a 60% fuel ratio to the total energy cost of purchases from power marketers as well as other suppliers that are unwilling or unable to provide PEC with actual fuel costs. Witness Peedin indicated that, to determine the 60% ratio, the Public Staff had performed a review of off-system sales made by PEC, Duke Power, and Dominion North Carolina Power for the twelve months ended December 31, 2004. According to witness Peedin, this analysis was similar to those performed by the Public Staff in support of the Marketer Stipulations entered into in 1997 and 1999 and covering these types of purchases. Witness Peedin stated that the Public Staff's analysis resulted in fuel ratios ranging from 58.66% to 61.74%, leading the Public Staff to conclude that the ratio to be applied should be set at 60%. Witness Peedin noted that similar analyses were performed for the fuel proceedings held in 2002, 2003, and 2004 and that the methodology underlying the analyses had been accepted by the Commission as reasonable in each fuel case since 1997. Witness Peedin also acknowledged that PEC had used the 60% ratio in its determination of recoverable test year fuel costs in this proceeding. 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 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 that this methodology for determining a proxy fuel cost meets the criteria set forth in the Commission's 1996 Duke fuel case order.

The use of a ratio to determine marketer fuel costs evolved with the emergence of an active wholesale bulk power market 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 in this proceeding. The Commission approved the use of the 60% ratio in the most recent Duke Power fuel proceeding, Docket No. E-7, Sub 780. The Commission accepts the use of a 60% ratio in this proceeding as recommended by Public Staff witness Peedin and adopted by PEC. There is no evidence in this proceeding to suggest that reliance on the Public Staff's recommended methodology and ratio would be unreasonable.

The Stipulation approved by the Commission in Docket No. E-2, Sub 784 outlined a proposal for PEC to recover $55.46 million of under-recovered fuel cost over a five-year period and provided that no more than $21,000,000 would be recoverable in any one year. In this proceeding, PEC is proposing to recover $21,000,000 of the under-recovered amount. The Company request is in accordance with the provisions of the Stipulation approved by the Commission in Docket No. E-2, Sub 784, and the Commission approves recovery of the $21,000,000 in this proceeding.

As noted above, the Agreement filed in this case provides for an EMF increment factor of 0.303 cents/kWh (0.313 cents/kWh including gross receipts tax), as recommended by Public Staff witness Peedin. With the Public Staff purchased power adjustment, the EMF amount eligible for recovery in this proceeding is $108,662,142. The Agreement also provides for a FERC audit settlement decrement rider of 0.007 cents/kWh (0.007 cents/kWh with gross receipts tax) to refund $2,431,000 to North Carolina retail customers over a one-year period, again as recommended by Public Staff witness Peedin.

The Commission acknowledges that PEC is entitled by law to recover 100% of its prudently incurred fuel cost. Based on the evidence in the record, the Commission finds that the proposed EMF amount of $108,662,142, consisting of $87,662,142 of test period under-recovery in this proceeding and $21,000,000 of the under-recovery deferred from Docket No. E-2, Sub 784, is appropriate. This under-recovery equates to an EMF increment rider of 0.303 cents/kWh (0.313 cents/kWh including gross receipts tax) that will remain in rates for a time period not to exceed one year from the effective date of this Order. The Commission also finds that the FERC settlement decrement rider of 0.007 cents/kWh (0.007 cents/kWh including gross receipts tax) is appropriate and should be approved.

In summary, based on the evidence of record, the Commission finds and concludes that the proper fuel factor to adopt in this case is 1.775 cents/kWh. This factor is an increase of 0.499 cents/kWh (0.516 cents/kWh with gross receipts tax) from the base fuel factor of 1.276 cents/kWh approved in PEC's last general rate case, Docket No. E-2, Sub 537. The Commission also finds that PEC should be allowed to recover the test period under-recovery of $87,662,142 and $21,000,000 of the under-recovery deferred from Docket No. E-2, Sub 784, and eligible for recovery in this case pursuant to the Stipulation agreed to by the parties and approved by the Commission in that docket, and that the appropriate EMF increment rider for purposes of this proceeding is 0.303 cents/kWh (0.313 cents/kWh including gross receipts tax). Finally, the Commission finds that PEC should be allowed to implement a FERC audit settlement decrement rider of 0.007 cents/kWh (0.007 cents/kWh with gross receipts tax) to refund $2,431,000 to North Carolina retail customers over a one-year period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 11

The evidence supporting this finding can be found in the direct testimony of CUCA witness O'Donnell and the rebuttal testimony of PEC witness Coats.

CUCA, in the prefiled testimony of Kevin O'Donnell, asserted that PEC's forecasted cost of natural gas during the time period of October 1, 2005, through September 30, 2006, was excessive and should be reduced. In response, PEC witness Coats testified that the natural gas price forecast relied upon by witness O'Donnell was the Henry Hub NYMEX futures prices as of July 25, 2005, for the future period of October 2005 through September 2006. Witness Coats testified that Henry Hub is an intersection of several major pipelines and is located in southern Louisiana. Since it is a common industry practice to price natural gas at the Henry Hub location, witness O'Donnell apparently assumed that the natural gas price referenced in witness Coats' direct testimony of $8.37/Dt was a Henry Hub based commodity cost. Witness Coats noted that the forecasted natural gas price of $8.37/Dt utilized in PEC's Application included not only the Henry Hub commodity cost, but also the variable costs incurred to transport the gas from Henry Hub to PEC's generation plants. Witness Coats stated that these variable transportation costs ranged from 25 cents to $1.70 per Dt and that witness O'Donnell's forecasted price of $7.90/Dt did not reflect any variable transportation cost. Finally, witness Coats testified that, once these variable costs were added to witness O'Donnell's Henry Hub price, the minimum price of the natural gas delivered to PEC's plants ranged from a low of $8.58/Dt to a high of $9.21/Dt, all of which exceeded the natural gas price used by PEC of $8.37/Dt.

In addition, during the hearing witness Coats testified that he had looked at the NYMEX strip prices on August 8, 2005, and found that for October 2005 through September 30, 2006, the average price of natural gas was $8.90/Dt and that in several of those months the price was more than a dollar higher than PEC's forecast.

Based on the foregoing, the Commission finds and concludes that the forecasted natural gas price of $8.37/Dt utilized by PEC, which includes the Henry Hub commodity cost and the variable cost incurred to transport natural gas to PEC generating plants, is reasonable for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 12

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

The Company proposed increasing the MDC rating for Brunswick Unit No. 1 from 872 MWs to 938 MWs effective January 1, 2005. No party offered any testimony challenging this change; therefore, the Commission accepts the MDC change as proposed by the Company.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after October 1, 2005, PEC shall adjust the base fuel component in its North Carolina retail rates by an increment of 0.499 cents/kWh (0.516 cents/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 case.

2. That PEC shall establish an EMF Rider as described herein to reflect an increment of 0.303 cents/kWh (0.313 cents/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, 2005, and expiring September 30, 2006.

3. That PEC shall establish a decrement rider of 0.007 cents/kWh (0.007 cents/kWh with gross receipts tax) for a 12-month period beginning October 1, 2005, and expiring September 30, 2006, to refund $2,431,000 to North Carolina retail customers resulting from a FERC settlement.

4. That the Settlement Agreement entered into by PEC, CIGFUR II, and the Public Staff and filed with the Commission by the Public Staff on July 25, 2005, as revised on September 6 and 12, 2005, is approved and the terms and conditions of that Settlement Agreement are hereby adopted by the Commission.

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

6. That PEC shall notify its North Carolina retail customers of the fuel charge adjustments approved herein by including the customer notice attached hereto as Appendix A 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.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of September, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr092605.01

APPENDIX A

PEC BILL MESSAGE

The North Carolina Utilities Commission issued an Order on September 26, 2005, after public hearings and review, approving a fuel charge increase of approximately $138 million in the rates and charges paid by North Carolina retail customers of Progress Energy Carolinas, Inc. The same Order approved a rate decrease of approximately $3 million related to a settlement between the Company and the Federal Energy Regulatory Commission. The net rate increase will be effective for service rendered on and after October 1, 2005, and will result in a monthly rate increase of $3.77 for a typical customer using 1,000 kWh per month.

DOCKET NO. E-7, SUB 780

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

HEARD: Tuesday, May 6, 2004, 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; Commissioners J. Richard Conder and Commissioner Howard N. Lee

APPEARANCES:

For Duke Power, a division of Duke Energy Corporation:

Lara S. Nichols, Assistant General Counsel, Duke Power, 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:

Lucy E. Edmondson, 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 Air Products and Chemicals, Inc.:

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

BY THE COMMISSION: On March 9, 2005, consistent with an extension of time granted by the Commission on March 4, 2005, Duke Power, a division of Duke Energy Corporation (Duke Power 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 16, 2005, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice.

On March 7, 2005, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene which was allowed by the Commission on March 18, 2005. On March 31, 2005, Air Products and Chemicals, Inc., filed a petition to intervene which was allowed by the Commission on April 5, 2005. The intervention of the Public Staff is noted pursuant to Commission Rule R1-19(e). On April 15, 2005, 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 13, 2005, Duke Power filed a Motion for Leave to File Testimony in which the Company requested that Dwight L. Jacobs be added as an additional witness in this proceeding and that the testimony attached to Duke Power's Motion be treated as Mr. Jacobs' prefiled testimony for purposes of this proceeding. On April 15, 2005, the Commission allowed Duke Power's Motion relating to Mr. Jacobs' testimony.

On April 20, 2005, the Public Staff filed a notice of affidavits and the affidavits of Thomas S. Lam, Utilities Engineer, Electric Division; Michael C. Maness, Electric Section Supervisor, Accounting Division; and Darlene P. Peedin, Staff Accountant, Accounting Division. On April 29, 2005, CUCA gave notice that it wished to cross examine Public Staff witnesses Lam, Maness and Peedin pursuant to G.S. 62-68.

On April 28, 2005, Duke Power filed the supplemental testimony of Janice D. Hager.

On May 2, 2005, Duke Power 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 3, 2005. M. Elliott Batson, Manager, Coal and Bulk Material Procurement; Dwight L. Jacobs, Vice President and Controller; and Janice D. Hager, Vice President, Rates & Regulatory Affairs, presented direct testimony for the Company. CUCA waived its request to cross-examine Public Staff witnesses Lam and Peedin. The Commission admitted into evidence the affidavits and exhibits of Thomas S. Lam, Utilities Engineer, Electric Division, and Darlene P. Peedin, Staff Accountant, Accounting Division. Additionally, Michael C. Maness, Electric Section Supervisor, Accounting Division, presented direct testimony on behalf of the Public Staff. No other party presented witnesses and no public witnesses appeared at the hearing.

After the hearing, the parties filed briefs and proposed orders on June 1, 2004, as allowed by the Commission.

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

FINDINGS OF FACT

1. Duke Energy Corporation is a duly organized corporation existing under the laws of the State of North Carolina. Duke Power, a division of Duke Energy Corporation, 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 Power 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, 2004.

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

4. The test period per book system sales are 76,564,000 MWH.

5. The test period per book system generation is 87,187,423 MWH and is categorized as follows:

Generation Type	MWH
Coal	44,637,655
Oil and Gas	128,567
Light Off	- -
Nuclear	39,218,381
Hydro	1,783,349
Net Pumped Storage	(739,022)
Purchased Power	1,482,781
Catawba Contract Purchases	-
Catawba Interconnection Agreements	566,154
Interchange	109,558
Total Generation	87,187,423

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

7. The adjusted test period system sales for use in this proceeding are 76,974,356 MWH.

8. The adjusted test period system generation for use in this proceeding is 87,946,214 MWH and is categorized as follows:

Generation Type	MWH
Coal	45,030,701
Oil and Gas	117,170
Light Off	-
Nuclear	40,459,199
Hydro	1,684,000
Net Pumped Storage	(827,637)
Purchased Power	1,482,781
Total Generation	87,946,214

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

A. The coal fuel price is $22.75/MWH.
B. The oil and gas fuel price is $113.49/MWH.
C. The appropriate Light Off fuel expense is $8,306,000.
D. The total nuclear fuel price is $4.25/MWH.
E. The nuclear fuel price for Catawba generation is $4.04/MWH.
F. The purchased power fuel price is $30.09/MWH.
G. The adjusted level of fuel credits associated with intersystem sales is $149,711,000.

10. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 60% 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 $1,113,104,000.

12. The proper fuel factor for use in this proceeding is 1.4461¢/kWh, excluding gross receipts tax.

13. The Company's North Carolina test period jurisdictional fuel expense under-collection was $16,589,000. The pro forma North Carolina jurisdictional sales are 53,823,443 MWH.

14. The Company's Experience Modification Factor (EMF) is an increment of 0.0308¢/kWh, excluding gross receipts tax.

15. It is reasonable for the Company to flow the revenue requirement related to excess accumulated deferred income taxes on property, plant and equipment to North Carolina retail customers during the 2005-2006 fuel clause billing period. The North Carolina retail allocation of revenue requirement for the excess accumulated deferred income tax liability is $106,289,000.

16. The deferred tax decrement rider is 0.1975¢/kWh, excluding gross receipts tax.

17. The final net factor to be billed to Duke Power's North Carolina retail customers during the 2005-2006 fuel clause billing period is 1.2794¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 1.4461¢/kWh, the EMF increment of 0.0308¢/kWh, and the deferred tax decrement rider of 0.1975¢/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 31st as the test period for Duke Power. The Company's filing was based on the 12 months ended December 31, 2004.

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, 2004. In addition, the Company files monthly reports of its fuel costs pursuant to Commission Rule R8-52(a).

Duke Power 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.

No 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 evidence to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

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

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

Company witness Hager testified that the test period per book system sales were 76,564,000 MWH and test period per book system generation was 87,187,423 MWH. The test period per book generation is categorized as follows:

Generation Type	MWH
Coal	44,637,655
Oil and Gas	128,567
Light Off	-
Nuclear	39,218,381
Hydro	1,783,349
Net Pumped Storage	(739,022)
Purchased Power	1,482,781
Catawba Contract Purchases	-
Catawba Interconnection Agreements	566,154
Interchange	109,558
Total Generation	87,187,423

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

Witness Hager testified that Duke Power achieved a system average nuclear capacity factor of 90.23% for the test period and that the most recent (1999-2003) NERC five-year average nuclear capacity factor for all pressurized water reactor units is 87.42%. The affidavit of Public Staff witness Lam also included this information.

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 76,564,000 MWH and 87,187,423 MWH, respectively. 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 the absence of evidence to the contrary, the Commission concludes that the levels of per book system sales of 76,564,000 MWH and per book system generation of 87,187,423 MWH are reasonable and appropriate for use in this proceeding.

Based upon the requirements of Commission Rule R8-55(c)(1), the historic and reasonably expected performance of the Duke Power system, and the agreement of the Public Staff, the Commission concludes that the 92% nuclear capacity factor and its associated generation of 40,459,199 MWH, including 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 FINDINGS 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 positive 410,356 MWH and a positive 758,791 MWH to per book system sales and generation, respectively, for adjustments relating to normalization for weather, customer growth, the Catawba Interconnection Agreement and line losses/Company use, based on a 92% normalized system nuclear capacity factor. She, therefore, calculated an adjusted system sales level of 76,974,356 MWH and an adjusted system generation level of 87,946,214 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 76,974,356 MWH and 87,946,214 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 having found a system nuclear capacity factor of 92% to be reasonable and appropriate in Finding of Fact No. 6, that the adjustment to per book system generation of a positive 758,791 MWH and the resulting adjusted test period system generation level of 87,946,214 MWH are both reasonable and appropriate for use in this proceeding. Total adjusted generation is categorized as follows:

Generation Type	MWH
Coal	45,030,701
Oil and Gas	117,170
Light Off	-
Nuclear	40,459,199
Hydro	1,684,000
Net Pumped Storage	(827,637)
Purchased Power	1,482,781
Total Generation	87,946,214

The Commission also finds the adjusted sales level of 76,974,356 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 Power's fossil fuel costs during the test year and changes expected in 2005. Witness Batson described the 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 Central Appalachia coal, limited production response to this increased demand, changing export market conditions for Central Appalachia coal, increasing mining operating costs, high natural gas prices and transportation complexities associated with alternative coal sources. Duke Power benefited from favorably priced coal contracts negotiated in previous years, which resulted in significantly lower average coal costs in the test year compared to prevailing market prices.

Witness Batson further testified that, as Duke Power's existing coal contracts expire, they will be replaced at market prices that are 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 2004 for deliveries starting in 2005, unsolicited offers from several producers, and forward coal prices as published by coal brokers that indicated Central Appalachia coal prices for the balance of 2005 and first half of 2006 in the low to upper $50's per ton for contract arrangements and the upper $50's to low $60's per ton for near term spot arrangements. This data indicates that the Company's cost of coal will be increasing in 2005 compared to 2004, although Duke Power's average cost of coal will be significantly below the projected market price for Central Appalachia coal.

Witness Batson testified that average coal transportation costs increased in the test year due to escalating tariff rates and fuel surcharges applied by the Norfolk Southern Railway (NS) and CSX Transportation (CSX) as a result of increasing fuel oil prices. Witness Batson also testified as to the status of the pending litigation between Duke Power and NS and CSX before the Surface Transportation Board (STB) regarding the freight rates the Company must pay to deliver coal to seven of its coal-fired stations. On October 20, 2004, the STB issued final decisions in both cases upholding all of the challenged rail transportation rates. Subsequently, Duke Power initiated a "phasing" proceeding in both cases in which the Company is seeking to have the sudden increases imposed gradually. Duke Power also appealed the STB's decisions to the United States Court of Appeals for the District of Columbia. The Company is not aware of any further significant changes in transportation costs in 2005, unless the STB grants relief in the form of a phasing-in of tariff rates.

Witness Batson further testified about initiatives the Company is pursuing to limit exposure to regional coal market price increases and to help stabilize and control coal costs. The Company's comprehensive coal procurement strategy includes having an appropriate mix of contract and spot purchases, staggering contract expirations, pursuing contract extension options that provide flexibility to extend terms within a price collar and pursuing options that provide flexibility to increase or decrease volumes.

In its brief, CUCA states that Duke Power's failure to test burn non-Appalachian coal in its generating units is inexcusable and imprudent under existing market conditions. Therefore, CUCA asks that the Commission remind Duke Power of its obligation to proactively and timely explore the feasibility of new and alternative fuel sources in order to satisfy the prudency standard set forth in G.S. 62-133.2.

According to the testimony of witness Batson, Duke Power's coal-fired generation plants were designed to burn Central Appalachia bituminous coal with a BTU value of 12,000 or higher per pound and a sulfur content of approximately one percent. When the delivered cost results in fuel savings, the Company blends coals with lower BTU values at several of its plants where it can do so without creating operational issues. On a system basis, approximately five to ten percent of Duke Power's coal burn is lower BTU coal. Further, witness Batson testified that the Company is developing the ability to burn non-Central Appalachia coal in the future to diversify the Company's coal supply in order to provide flexibility to take advantage of purchase opportunities in changing domestic and international markets. In light of the installation of scrubbers at certain of Duke Power's coal-fired facilities that will come on line in 2006 through 2008, the Company is evaluating the operational parameters of using coals with higher sulfur content from Pennsylvania, Illinois and Indiana. Additionally, Duke Power is evaluating the ability to use western sub-bituminous coal, such as Powder River Basin Coal, and imported coal, specifically coal from Columbia and Venezuela.

In response to questions from the Commission and counsel for CUCA, witness Batson explained the transportation and operational issues associated with using non-Central Appalachian coals. Currently, congestion on the railroads is limiting Duke Power's ability to obtain transportation rates to ship Powder River Basin coal in order to perform a test burn. Such a test is necessary to evaluate all of the operational issues associated with using sub-bituminous coal. This type of coal is more volatile and contains more moisture than the type of coal the Company's coal-fired plants were designed to burn. These differences could result in the need to make significant plant modifications, including changes to the coal-handling systems and the boiler configuration. Duke Power is also looking to test the ability to blend non-Central Appalachia coal with Central Appalachia coal. The Company evaluates the use of non-Central Appalachia coals on a total cost basis, considering the fuel cost on a delivered basis, any increased O&M costs and the cost of any capital modifications that would be required.

Witness Batson also testified that an additional effort to control coal costs involves Duke Power entering into agreements with Oak Mountain Products II, LLC (OMP) to locate a synthetic fuel production facility at Marshall Steam Station in 2005. Batson Exhibit 4, which was filed under seal to protect commercially sensitive, confidential information, sets forth a summary of the agreements related to this synthetic fuel facility. Witness Batson testified that, once the facility is up and running, Duke Power expects to purchase approximately four million tons of synthetic fuel annually through the end of 2007, resulting in twelve to thirteen million dollars of fuel cost savings annually. Similar to the agreements with DTE Belews Creek, LLC (DTE) that were addressed in Duke Power's 2004 fuel adjustment proceeding (Docket No. E-7, Sub 746), the OMP synthetic fuel facility will be located on the Company's property and Duke Power will provide consulting services. Annually, OMP will pay Duke Power $50,000 under a lease agreement and $50,000 under a consulting services agreement. The Company does not have any ownership in OMP.

Counsel for CUCA also asked witness Batson about synthetic fuel purchases during the test year. Witness Batson testified that in 2004 the Company continued to make synthetic fuel purchases from DTE and that the agreements related to DTE had not changed since the Commission considered them in Docket No. E-7, Sub 746. In addition, the Company purchased synthetic fuel from several different producers in the market. Unlike the DTE and OMP arrangements, these producers do not have synthetic fuel production facilities located at a Duke Power generation station. The Company does not have any related transactions with these producers.

The Commission believes that the record in this proceeding shows that Duke Power has appropriately explored and continues to investigate the feasibility of new and alternative fuel sources and there is no evidence of imprudency in this regard. Should any allegations of imprudency with respect to this issue arise in future proceedings, the Commission will decide the issues presented to it based on the record in those proceedings in accordance with the prudency standard set forth in G.S. 62-133.2.

Duke Power 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 9,466 BTU/MWH. Achievement of this heat rate continues Duke Power'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 $22.75/MWH.
B. The oil and gas fuel price is $113.49/MWH.
C. The appropriate Light Off fuel expense is $8,306,000.
D. The total nuclear fuel price is $4.25/MWH.
E. The nuclear fuel price for Catawba generation is $4.04/MWH.
F. The purchased power fuel price is $30.09/MWH.
G. The adjusted level of fuel credits associated with intersystem sales is $149,711,000.

Items A, B, C, D, F and G are set forth on or derived from Hager Exhibit 1, Schedule 2(c). Item E is set forth on Hager Appendix 1, Page 9.

On cross-examination, counsel for CUCA asked witness Hager about various monthly fuel and power plant performance reports filed by the Company in Docket No. E-7, Sub 745, including questions regarding reports showing positive fuel costs and negative net generation in a given month. Witness Hager noted that on a month-to-month basis there may be adjustments from prior months that are netted on the monthly fuel reports, including adjustments for the fuel component of purchased power where the supplier provides Duke Power with actual fuel cost information. Witness Hager also explained that a peaking facility may consume fuel to operate for very short periods; over the course of a given month it may consume more electricity for its auxiliary load than it produces. Witness Hager described this phenomenon as typical.

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 witnesses Peedin and Maness and the exhibits of Company witness Hager.

Public Staff witness Peedin stated in her affidavit that her purpose was to present 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 Power, 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, 2004. 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, 2003 and 2004 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 Power'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." *Order Approving Fuel Charge Adjustment,* Docket No. E-7, Sub 575 (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 fuel-to-energy cost percentage present in 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 Power fuel case Order.

As part of its current review, the Public Staff analyzed the utilities' off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 58.66% to 61.74%, as set forth on Peedin Exhibit I. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel percentage should be 60%.

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 Power 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 Power 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 and are subject to Commission review. Finally, no party to this proceeding has elicited evidence of any alternative information available concerning the fuel cost component of purchases made from power marketers or other relevant sellers of power to Duke Power. 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 Power fuel case Order and is reasonable for use in 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 utilities' off-system sales information in different ways. The Public Staff's analyses resulted in percentages ranging from 58.66% to 61.74% and, based on its analyses, the Public Staff concluded that 60% is an appropriate and reasonable fuel proxy percentage for purposes of this proceeding. Public Staff witness Maness testified that in connection with this proceeding the Company applied a 60% factor to purchases from entities that do not provide actual fuel costs, thus indicating its agreement with the Public Staff's fuel proxy percentage. Public Staff witness Maness also testified that he reviewed the purchases to which Duke Power applied the factor and believes the Company has applied the factor in a reasonable manner.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use the 60% 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 Lam and Maness.

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 $1,113,104,000 and a base fuel factor of 1.4461¢/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 0.3429¢/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 Maness 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 review of the Company's filing, prior Commission Orders, the Monthly Fuel Reports filed by the Company with the Commission, and other Company data provided to the Public Staff. Additionally, the procedures included review of certain specific types of expenditures impacting the Company's test year fuel cost, including nuclear fuel disposal costs, federally mandated payments for decommissioning and decontamination of Department of Energy uranium enrichment facilities, payments to non-utility generators, and purchases of power from other suppliers who may or may not have provided the actual fuel costs associated with those purchases. Also, the Public Staff's procedures included reviews of source documentation of fuel costs for certain selected Company generation resources. Performing the Public Staff's investigation required the review of numerous responses to written and verbal data requests, as well as a site visit to the Company's offices.

Witness Maness testified that a portion of the test year costs incorporated into the calculation of the EMF rider is made up of fuel expenses associated with purchases and sales of MWH denoted as Energy Imbalance. Witness Maness explained that Energy Imbalance is a service provided by Duke Power pursuant to its Open Access Transmission Tariff to certain wholesale transmission service customers that enables these customers to rely upon the Company to make up any differences between the load the customer schedules to take off of Duke Power's transmission system and the customer's actual load. The Company calculates fuel cost related to both the sales and purchases undertaken pursuant to Energy Imbalance service. Witness Maness testified that the Public Staff identified $1,578,806 included in the test year fuel expenses related to sales of Energy Imbalance MWH that should have been treated as a fuel credit and deducted from fuel expenses. The correction of this error results in an adjustment that reduces the Company's test year system fuel expenses by $3,157,614 and the North Carolina retail portion of said expenses by $2,199,000. As a result of his investigation, including this adjustment, witness Maness calculated a net fuel under-recovery of $16,593,000.

In her supplemental testimony, Duke Power witness Hager presented Revised Hager Exhibit 6 setting forth Duke's revised recommended EMF increment. Witness Hager testified that she had reflected Mr. Maness' recommended adjustment to test year fuel expense in this exhibit. The total under-recovery set forth on Revised Hager Exhibit 6, page 1 of 2 is $16,589,000. Witness Maness noted that the $4,000 difference between the Company's calculation and the Public Staff's calculation was due to rounding differences. Witness Maness testified that the Public Staff accepted the Company's calculation and recommended that the under-recovery be found to be $16,589,000.

In its brief, CUCA states that the EMF increment proposed by Duke Power is excessive because it has not been shown by the preponderance of the evidence that its entire fuel costs were prudently incurred. Specifically, CUCA argues that Belews Creek Unit 1 was out of service from May 26, 2004, through July 4, 2004, due to a fire in that unit's secondary air heater. CUCA then claims that since Duke Power's witness could not explain what caused the fire, what repairs were necessary and why the repairs took almost one and one-half months to complete, Duke Power failed to satisfy its burden of proving that all of its fuel costs were prudently incurred. Therefore, CUCA asks the Commission to determine the difference in fuel costs between the system operating with and without Belews Creek Unit 1 during the outage and deduct this difference from the fuel costs in order to calculate a lower EMF.

In response to cross-examination, re-direct examination, or questions from the Commission panel, Company witness Hager testified that Belews Creek Unit 1 had a forced outage from May 26, 2004, to July 4, 2004, due to a fire which damaged equipment that rendered the unit inoperable until the repairs were complete. Although witness Hager did not know how the fire occurred, she testified that the Company worked diligently to return the unit to service. Witness Hager also enumerated a detailed list of certain repairs to equipment which the Company performed to bring the unit back online. She added that, while these repairs were being done, Duke Power did additional work that would perhaps shorten future outages at the unit. She characterized this work as a fairly extensive repair process. Witness Hager also noted that Duke Power designs its system with a 17% planning reserve margin because outages are simply in the nature of operating generation systems.

G.S. 62-133.2(d) provides that the "burden of proof as to the correctness and reasonableness of the charge and as to whether the fuel charges were reasonable and prudently incurred shall be on the utility." The evidence clearly shows that Belews Creek Unit 1 was out of service due to a fire from May 26, 2004, until July 4, 2004. This outage was noted in the Company's monthly base load power plant performance reports, of which the Commission took judicial notice at the hearing. Duke witness Hager testified that the Belews Creek station had been rated as one of the country's most efficient coal-fired generating stations and that the Company's fuel costs during the test year were reasonable. Witness Hager provided a detailed list of the work performed during what she characterized as a "fairly extensive repair process" following the fire, and she testified that Duke Power worked diligently to return the unit to service. CUCA argues that Duke Power failed to satisfy its burden of proof herein because it did not adequately explain this fire or the repair work. CUCA asks that the increased fuel costs attributable to this outage be deducted in calculating the EMF increment.

Utilities Commission v. Intervenor Residents, 305 NC 62 (1982), involved the appeal of a general rate case order in which the Commission relied in part upon expenses allocated to the utility from affiliated companies to set rates. In Intervenor Residents, 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 paid to an affiliate "always rests with the utility," but 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 allocated to it by an affiliated company..." 305 NC at 76.

In the present case, witness Hager could not answer questions from CUCA's counsel as to how the fire at Belews Creek Unit 1 originated; however, the mere fact of a fire does not constitute evidence of negligence or imprudence, CUCA did not elicit any evidence suggesting that any negligence or imprudence caused the fire, and the Commission sees no reason to conduct an additional inquiry into this matter. In these circumstances, the Commission does not believe that witness Hager's inability to answer CUCA's questions, without more, establishes that the Company failed to meet its burden of proof. The Commission concludes, on the basis of witness Hager's testimony and the record as a whole, that Duke Power satisfied its burden of proof as to the reasonableness of its fuel costs during the test year.

Based upon the evidence in the record and the agreement of the Company and the Public Staff, the Commission concludes that Duke Power's reasonable North Carolina retail test period jurisdictional fuel expense under-collection is $16,589,000. Hager Exhibit 5 and Hager Revised Exhibit 6 set forth 53,823,443 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 Power witness Hager calculated the EMF increment by dividing the $16,589,000 fuel expense under-recovery by the adjusted North Carolina jurisdictional sales of 53,823,443 MWH to arrive at an EMF increment of 0.0308¢/kWh, excluding gross receipts tax. Public Staff witness Maness recommended the same EMF increment. The Commission concludes that the EMF increment of 0.0308¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding.

Duke Power witness Jacobs testified that, in addition to the EMF increment, the Company is proposing a decrement of 0.1975¢/kWh related to an accumulated deferred income tax liability. Witness Jacobs explained that this liability was accumulated over at least a ten year period in anticipation of tax liabilities that were not ultimately realized. The Company determined that it had accumulated approximately $153 million on a total system basis in revenue requirement related to excess deferred income taxes and proposes to flow the North Carolina retail portion to customers through the fuel clause factor during the 2005-2006 billing period. Duke Power witness Hager divided the North Carolina retail allocation of the revenue requirement for the excess accumulated deferred taxes of $106,289,000 by 53,823,443 MWH, producing a deferred tax decrement rider of 0.1975¢/kWh, excluding gross receipts tax. Witness Hager further testified that the deferred tax decrement rider, if approved, will not be applied as a reduction to the fuel factor when calculating the Company's over or under-recovery of fuel expense in the 2005 test year.

Public Staff witness Maness testified that the Public Staff reviewed certain Duke Power work papers and other documents related to the proposed rider and based upon this review, as well as the fact that the rider constitutes a rate reduction, the Public Staff recommends that the Commission approve it. Witness Maness further testified that the Public Staff recommends that the deferred tax decrement rider be clearly distinguished from any and all components of the approved fuel factor.

On cross-examination, counsel for CUCA asked witnesses Jacobs, Hager and Maness questions regarding allocation of the excess deferred income tax liability among customer classes. Witness Jacobs testified that based on his knowledge, the liability is not associated with a particular class of customers. Witness Hager testified that any consideration of how deferred income tax liability would be allocated among different classes of customers in a general rate case proceeding instead of in this proceeding would be speculative. Witness Maness testified that in this case, given the fact that this is a fuel proceeding and that Duke Power has proposed a rate reduction, the Public Staff felt that allocating the liability on a kWh usage methodology was reasonable and recommended it. He stated that as far as he knew, no functionalization or allocation of the deferred taxes to customer classes had been made. One of the Commissioners on the panel noted that, generally speaking, because industrial customers typically have higher load factors than other classes of customers, an allocation based upon kWh would be a favorable result for such customers.

The Commission finds and concludes that it is reasonable to flow the revenue requirement related to excess accumulated deferred income taxes to North Carolina retail customers during the 2005-2006 fuel adjustment billing period. Further, the Commission concludes that the North Carolina retail allocation of revenue requirement for the excess accumulated deferred income tax liability is $106,289,000, which when divided by the adjusted test year North Carolina retail sales of 53,823,443 MWH, produces a deferred tax decrement rider equal to 0.1975¢/kWh, excluding gross receipts tax. Given that Duke Power is proposing to flow this excess liability to retail customers through the fuel adjustment mechanism as a rate reduction, rather than seeking other treatment of this excess liability, the Commission also agrees that a kWh usage allocation methodology is reasonable and appropriate. Finally, the Commission notes that this deferred tax decrement should not be applied as a reduction to the fuel factor when computing the over- or under- collection of fuel costs for the 2005 test year in the next fuel charge adjustment proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in a net fuel factor of 1.4769¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 1.4461¢/kWh and the EMF increment rider of 0.0308¢/kWh. When the deferred tax decrement rider of 0.1975¢/kWh is subtracted from the net fuel factor so derived, the net factor to be billed to Duke Power's North Carolina retail customers during the 2005-2006 fuel clause billing period becomes 1.2794¢/kWh, excluding gross receipts tax.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after July 1, 2005, Duke Power shall adjust the base fuel cost approved in Docket No. E-7, Sub 487, in its North Carolina rates by an amount equal to a 0.3429¢/kWh increase (excluding gross receipts tax) and further that Duke Power shall adjust the resultant approved fuel cost by an increment of 0.0308¢/kWh (excluding gross receipts tax) for the EMF increment. The EMF increment is to remain in effect for service rendered through June 30, 2006.

2. That, effective for service rendered on and after July 1, 2005, Duke Power shall further adjust the rates approved in Docket No. E-7, Sub 487, by a deferred tax decrement rider equal to a 0.1975¢/kWh decrease (excluding gross receipts tax). The deferred tax decrement rider is to remain in effect for service rendered through June 30, 2006.

3. That Duke Power 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.

4. That Duke Power 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 15th day of June, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr060805.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 780

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	))))	NOTICE TO CUSTOMERS OF CHANGE IN RATES

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order on June __, 2005, after public hearings, approving a fuel charge net rate increase of approximately $150,867,000 on an annual basis in the rates and charges paid by the retail customers of Duke Power in North Carolina. The same Order approved a rate decrease of approximately

$109,854,000 related to excess deferred income taxes previously charged by Duke Power to North Carolina retail expenses. It is intended that the net rate increase of $41,013,000 will be in effect for service rendered for the period of July 1, 2005, through June 30, 2006. The rate increase was approved by the Commission after review of Duke Power's fuel expenses during the 12-month period ended December 31, 2004, 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, as well as the excess deferred income taxes noted above.

The change in approved rates will result in a monthly net rate increase of approximately $0.76 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of June, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. E-22, SUB 412
DOCKET NO. E-100, SUB 56

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 412)
In the Matter of)
Dominion North Carolina Power -)
Investigation of Existing Rates and Charges)
) ORDER APPROVING STIPULATION
DOCKET NO. E-100, SUB 56)
In the Matter of)
Decommissioning Costs for Nuclear Power)
Plants Owned and Operated by Carolina)
Power and Light Company, Duke Power)
Company, and Dominion North Carolina Power)

HEARD: Tuesday, January 18, 2005, at 7:00 p.m., Council Chambers, Ahoskie Town Hall, 201 W. Main Street, Ahoskie, North Carolina

Wednesday, January 19, 2005, at 7:00 p.m., Courtroom B, Pasquotank County Courthouse, 206 E. Main Street, Elizabeth City, North Carolina

Tuesday, January 25, 2005, at 7:00 p.m., Assembly Room, Williamston City Hall, Second Floor, 102 E. Main Street, Williamston, North Carolina

Wednesday, January 26, 2005, at 7:00 p.m., Banquet Hall, Kirkwood F. Adams Community Center, 1100 Hamilton Street, Roanoke Rapids, North Carolina

Tuesday, February 22, 2005, at 9:30 a.m., and Wednesday, March 2, 2005, at 1:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

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

FOR NUCOR STEEL- HERTFORD:

Joseph W. Eason, Nelson Mullins Riley & Scarborough LLP, 4140 Parklane Avenue, Glenlake One, Second Floor, Raleigh, North Carolina 27612

BY THE COMMISSION: On January 29, 2004, the Public Staff - North Carolina Utilities Commission (Public Staff) filed a petition in Docket No. E-22, Sub 412 requesting the Commission to (1) institute an investigation into the existing North Carolina retail rates and charges in effect for Virginia Electric and Power Company, d/b/a Dominion North Carolina

Power (DNCP), pursuant to G.S. 62-130(d), -133(a), -136(a), and -137 for the purpose of determining if the rates and charges are unjust and unreasonable and, if so, to determine the just and reasonable rates that DNCP should be allowed to charge thereafter; (2) require DNCP to file a Rate Case Information Report (NCUC Form E-1) for the twelve months ended December 31, 2003; (3) require DNCP to appear before the Commission and show cause in the form of prefiled testimony and exhibits why its existing rates and charges should not be found unjust and unreasonable and reduced for service rendered thereafter; and (4) take such further action as the Commission deems just and proper. On March 1, 2004, the Attorney General filed a notice of intervention pursuant to G.S. 62-20 and motion in support of the petition. On March 3, 2004, DNCP filed a response and motion to dismiss urging the Commission to conclude that there was no basis for a determination that its existing rates were unjust and unreasonable and that no investigation should be ordered.

On April 23, 2004, the Commission issued an order granting the Public Staff's petition; instituting an investigation into the justness and reasonableness of DNCP's North Carolina retail rates pursuant to G.S. 62-130(d), -133, and -136(a); declaring that the investigation would constitute a general rate case pursuant to G.S. 62-137; requiring the use of a test period consisting of the twelve months ended December 31, 2003, with appropriate adjustments; establishing deadlines for the filing of intervention petitions, DNCP's NCUC Form E-1, and prefiled direct and rebuttal testimony; establishing discovery guidelines; and setting the matter for hearing on January 11, 2005. On May 7, 2004, DNCP filed a motion for an extension of the procedural schedule. The Commission entered an order on May 13, 2004, rescheduling the hearing to February 22, 2005, and extending the dates for filing testimony, intervention petitions, DNCP's NCUC Form E-1, and prefiled direct and rebuttal testimony.

Petitions to intervene were filed by Carolina Utility Customers Association, Inc. (CUCA), on April 21, 2004, and Carolina Industrial Group for Fair Rates I (CIGFUR I) on April 29, 2004. On May 7, 2004, DNCP filed a motion to dismiss CUCA's petition. On May 13, 2004, the Commission entered orders granting the petition of CIGFUR I and denying the petition of CUCA. On November 5, 2004, Nucor Steel - Hertford (Nucor) filed a petition to intervene which was granted by order issued November 9, 2004. The intervention and participation of the Public Staff is recognized pursuant to G.S. 62-15 and Commission Rule R1-19(e).

On June 9, 2004, the Commission issued an order scheduling hearings for the purpose of receiving testimony from interested members of the public at various locations in DNCP's franchised territory and requiring customer notice.

On June 24, 2004, the Commission entered an order concluding that the disputed issues in Docket No. E-100, Sub 56, involving DNCP's 2002 nuclear decommissioning cost studies should be consolidated for investigation and hearing with the ongoing investigation of the justness and reasonableness of DNCP's North Carolina retail rates in Docket No. E-22, Sub 412.

On September 24, 2004, DNCP filed its NCUC Form E-1 and the testimony and exhibits of M. Stuart Bolton, Craig S. Ivey, Sunil Maheshwari, Charles A. Stadelmeier, and James H. Vander Weide. On January 24, 2005, Nucor filed the testimony and exhibits of Dennis W. Goins and J. Bertram Solomon. On the same date, the Public Staff filed the testimony and exhibits of

John R. Hinton, Kennie D. Ellis, Thomas S. Lam, Howard M. Lowdermilk, James S. McLawhorn, Karyl Crean, Michael C. Maness, and Randy T. Edwards.

On September 29, 2004, DNCP filed a motion for authority to capture and defer the North Carolina retail portion of certain costs associated with its efforts to form the Alliance Regional Transmission Organization (RTO) and to join PJM Interconnection, LLC (PJM), and a motion for reimbursement of costs to Dominion Alliance Holding, Inc., for the North Carolina retail portion of the costs incurred in connection with DNCP's efforts to form the Alliance RTO. On December 3, 2004, and December 8, 2004, respectively, the Public Staff and Attorney General filed responses to these motions. On December 7, 2004, the Commission issued an order deferring ruling on the motions until a decision on the merits was reached in Docket No. E-22, Sub 412.

On January 6, 2005, DNCP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural orders.

Public hearings were held in Ahoskie, Elizabeth City, Williamston, and Roanoke Rapids for the purpose of receiving public testimony. Gary Van Hooser, an employee of Fruit of the Loom, testified at the hearing in Williamston.

On February 11, 2005, DNCP filed a letter stating that the parties had reached a tentative settlement and requesting that the discovery schedule and the filing of rebuttal testimony be placed on hold. The Commission granted this request by order issued February 14, 2005. The matter came on for hearing on February 22, 2005, and all prefiled testimony and exhibits filed in this case were admitted into evidence without objection. All parties agreed to waive cross-examination. On February 23, 2005, the Commission issued an order requiring the prefiling of testimony supporting the settlement of the parties by March 1, 2005, and scheduling a hearing to receive the settlement on March 2, 2005. On March 1, 2005, DNCP filed an unexecuted, proposed Stipulation and Agreement of the parties and the prefiled testimony of David F. Koogler in support of the proposed stipulation. The hearing resumed on March 2, 2005, as scheduled.

On March 11, 2005, DNCP filed a Stipulation and Agreement executed by DNCP, the Public Staff, CIGFUR I, and Nucor (Stipulation). The Stipulation is attached to this Order as Exhibit A.

Based on the testimony and exhibits entered into evidence and the entire record in this proceeding, the Commission makes the following:

FINDINGS AND CONCLUSIONS

1. DNCP is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. DNCP is engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. DNCP is an unincorporated division of Virginia Electric and Power Company and has its office and principal place of business in Richmond, Virginia. Virginia Electric and Power Company is a wholly owned subsidiary of Dominion Resources, Inc.

2. DNCP is a public utility within the meaning of G.S. 62-3(23).

3. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of public utilities operating in North Carolina, including DNCP, under Chapter 62 of the General Statutes of North Carolina.

4. DNCP is before this Commission pursuant to G.S. 62-130(d), -133, and -136(a) for a determination of whether its rates and charges are unjust and unreasonable and, if so, the just and reasonable rates DNCP should be allowed to charge hereafter.

5. In its application and testimony filed at the direction of the Commission, DNCP presented evidence to justify an increase in its non-fuel revenue requirement of approximately $10.8 million, but did not propose a rate increase in this proceeding.

6. In its prefiled testimony, the Public Staff presented evidence to justify a decrease in DNCP's non-fuel revenue requirement of approximately $23.8 million.

7. The appropriate test period for use in this proceeding is the twelve months ended December 31, 2003, with appropriate adjustments, as updated by the parties.

8. DNCP submitted evidence in this case with respect to revenue, expenses and rate base using a test period consisting of the twelve months ended December 31, 2003, with updating adjustments, as directed by the Commission. The Public Staff used the same test period, with updating adjustments. The Stipulation was based upon the same test period, as updated by the Public Staff.

9. The Stipulation executed by DNCP, the Public Staff, Nucor and CIGFUR I, is unopposed by any party. While not a signatory to the Stipulation, the Attorney General does not object to the Stipulation and will not appeal any order of the Commission approving and implementing the Stipulation. Thus, the Stipulation settles all matters in this docket.

10. The Stipulation provides for a net reduction in DNCP's annual non-fuel revenue of $12,000,000 from its North Carolina retail operations, which the Stipulating Parties present as an appropriate resolution of the contested matters in this proceeding and which will result in just and reasonable rates for DNCP, without a determination of each matter presented in the pre-filed testimonies of the parties related to rate base, operating revenues and expenses, and rate of return. The Commission makes no determination with respect to DNCP's authorized rates of return on common equity and rate base in this proceeding. Thus, DNCP has no Commission-authorized rate of return on common equity or rate base as of the date of this Order.

11. The Stipulation provides for allocation of the $12,000,000 reduction among the rate classes as set forth in Section 2(B) of the Stipulation, based upon the billing units recorded in the test year adjusted for the effects of weather, customer growth and increased usage updated through October 31, 2004, as set forth in Section 2(C) of the Stipulation. The Stipulation provides that rates will be designed so that no customer's monthly bill will increase. The Stipulation also provides that DNCP may increase its Service Connection Charge to reflect costs to produce additional annual revenue of approximately $373,000, provided that a corresponding decrease in revenue is distributed proportionately among the customer classes in addition to the base revenue decrease as shown in Section 2(B) of the Stipulation.

12. The Commission has reviewed the Stipulation, including the proposed annual non-fuel revenue decrease of $12,000,000 agreed to by the parties, and concludes that this prospective reduction in the level of base rates to be paid by DNCP's North Carolina retail customers is a reasonable outcome of this proceeding and is just and reasonable.

13. The Stipulation provides that none of DNCP's North Carolina retail electric rates will be increased or decreased from the levels established pursuant to the Stipulation 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 or (2) to flow through the effects of changes in federal or state income tax law or changes in the gross receipts tax rate applicable to DNCP. The Stipulation provides that none of the Stipulating Parties will initiate any proceeding which seeks to increase or decrease DNCP's non-fuel retail electric rates during the Rate Change Moratorium Period other than to initiate a proceeding under exception (2) above. In any proceeding addressing DNCP's base rates during the Rate Change Moratorium Period, the Stipulating Parties agree to support and defend the terms of the Stipulation. The record in this case establishes that the Stipulating Parties do not seek to limit the Commission in the performance of its statutory duties and responsibilities during the Rate Change Moratorium Period. The Commission finds these aspects of the Stipulation to be reasonable, subject to the provision that the Commission is not limited in the exercise of its jurisdiction over DNCP pursuant to Chapter 62 of the General Statutes of North Carolina.

14. The Commission finds that the allocation of the revenue decrease among the rate classes as set forth in Section 2 of the Stipulation is just and reasonable.

15. The Stipulation provides that DNCP will not record any regulatory deferrals not previously authorized by the Commission for any changes in costs incurred or revenues realized during the Rate Change Moratorium Period, except, with Commission approval, on the grounds that such deferral is necessary to address pronouncements of entities authorized to set accounting standards (e.g., the Financial Accounting Standards Board). The Commission finds that this provision should be adopted.

16. The Stipulation provides an agreement and recommendation that an order accepting the Stipulation contain the following:

(a) 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.
(b) During the Rate Change Moratorium Period and afterwards, DNCP will continue to be subject to Commission Rule R8-27, including the Uniform System of Accounts adopted pursuant to that Rule, all other applicable accounting requirements and practices of the Commission, and Statement of Financial Accounting Standards No. 71 of the Financial Accounting Standards Board.

The Commission finds that these aspects of the Stipulation are just and reasonable and should be incorporated into this Order.

17. The Commission finds that DNCP's base fuel factor included in its base rates will be 1.647¢/kWh, excluding gross receipts tax, or 1.701¢/kWh, including gross receipts tax, which

is the same as the fuel factor approved in DNCP's most recent fuel charge adjustment proceeding, Docket No. E-22, Sub 422, pursuant to G.S. 62-133.2. The Stipulation provides that the methods and procedures to be used in calculating the fuel factor in future fuel proceedings will be the same as those followed in Docket No. E-22, Sub 422, except for changes to the methodology for normalizing kWh sales for weather, as set forth in Section 4(B) of the Stipulation. The Commission finds these aspects of the Stipulation to be just and reasonable.

18. The Stipulation provides that DNCP will file two annual cost-of-service studies: one using the Summer/Winter Peak and Average methodology and the other using a Summer/Winter Peak and Average methodology with no assignment of production plant to Schedule NS. The Commission finds this provision to be reasonable.

19. The Commission finds that DNCP's annual depreciation expense during the Rate Change Moratorium Period will be based on the depreciation rates reflected in DNCP's depreciation studies filed on December 13, 2002, in Docket No. E-22, Sub 406.

20. The Stipulation provides that beginning with the Effective Date of the rate change, DNCP will discontinue recording and funding $1,843,000 of annual nuclear decommissioning expense for North Carolina retail jurisdictional purposes and, unless otherwise ordered by the Commission, will record a nuclear decommissioning expense of $0 during the Rate Change Moratorium Period. In no event will DNCP record a nuclear decommissioning expense less than $0 or remove monies from the North Carolina retail decommissioning fund during the Rate Change Moratorium Period. For calendar year 2005, DNCP will record and fund a pro rata portion of $1,843,000, as of the effective date of the rate change pursuant to the Stipulation. The Commission finds this provision to be reasonable.

21. Regarding Demand Side Management (DSM) costs, the Stipulation provides that DNCP will record and amortize a regulatory liability and related deferred income tax costs associated with North Carolina retail accumulated DSM cost over-recoveries, in accordance with criteria set forth in Section 8 of the Stipulation. As of the effective date of the rate change, the DSM deferral procedure approved by the Commission in Docket No. E-100, Sub 64 will cease to be in effect. The Commission finds the DSM provision of the Stipulation to be reasonable.

22. The Stipulation provides that, as of the effective date of the rate change, DNCP will write-off as a non-utility expense the North Carolina retail portion of any previously deferred Alliance RTO or PJM start-up costs, as well as any deferred or accrued carrying charges. In the event this Commission approves DNCP's application to join PJM, DNCP will record the PJM administrative fees incurred for purposes of serving its North Carolina retail load during the Rate Change Moratorium Period in accordance with the Commission's order in Docket No. E-22, Sub 418. DNCP has also agreed not to defer or seek approval for deferral of the North Carolina portion of any RTO/ISO start-up costs or administrative fees incurred during the Rate Change Moratorium Period. The Commission finds these provisions to be reasonable.

23. The Stipulation provides that DNCP will record and amortize for North Carolina regulatory accounting purposes regulatory assets related to the North Carolina retail portion of the above-market portion of DNCP's buyouts of certain specified non-utility generation contracts, as well as deferred income tax savings. Section 10 of the Stipulation sets forth the criteria for the appropriate regulatory treatment of these buyout costs, which the Commission finds to be reasonable.

24. The Commission finds reasonable Section 11 of the Stipulation, which sets forth regulatory treatment of the repair and restoration expenses associated with Hurricane Isabel, including an amortization period presumed to have begun in mid-September of 2003. The actual amortization terms are set forth in the Stipulation, and the Commission approves these terms.

25. DNCP shall provide the Commission and Public Staff with revised ES-1 reports, recalculated to take into account the presumed regulatory assets, deferred income taxes, and amortizations set forth in Sections 10 and 11 of the Stipulation. Such reports shall be provided within 90 days from the date of this Order.

26. The Stipulation includes provisions establishing a process under which DNCP and the Public Staff will pursue discussions to address and resolve service quality-related issues, which the Commission adopts as reasonable.

27. DNCP and Nucor have agreed to amend their agreement for electric service and to revise Schedule NS accordingly. The revised Schedule NS and the amended service agreement will be filed with the Commission for approval in this docket in accordance with the orders and rules of the Commission. The Stipulation provides that the service agreement and Schedule NS, as amended, shall not be further modified or terminated prior to October 31, 2010, without the written consent of Nucor. The Commission finds the revised service agreement and Schedule NS, as set forth in Section 14 of the Stipulation, to be just and reasonable.

28. The Stipulation provides that Schedule 6VP will be revised to eliminate the current termination date and will be filed with the Commission for approval. The Commission finds this provision to be reasonable.

29. The Commission finds that all of the provisions of the Stipulation are fair and reasonable under the circumstances of this proceeding and should be approved.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 1 - 6

The evidence supporting these findings of fact is contained in the verified application and NCUC Form E-1 filing of DNCP; the testimony and exhibits of the witnesses and the record in this docket.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 7 - 8

These findings are consistent with the Commission's April 23, 2004 Order establishing this proceeding and are supported by DNCP's filing and the testimony of witnesses. The findings are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 9 - 11

These findings are supported by the Stipulation, DNCP's application and NCUC Form E-1 filing, the testimony and exhibits and the record in this proceeding. The findings are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 12 - 14

These findings are supported by the Stipulation, DNCP's application and NCUC Form E-1 filing, the testimony and exhibits and the record in this proceeding. The findings are not contested by any party.

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION NO. 15

This finding is supported by the Stipulation, DNCP's application and NCUC Form E-1 filing, the testimony and exhibits and the record in this proceeding. The finding is not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 16 – 28

These findings are supported by the Stipulation, DNCP's application and NCUC Form E-1 filing, the testimony and exhibits and the record in this proceeding. The findings are not contested by any party.

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION NO. 29

The revenue reduction and allocation, accounting treatment, and other issues addressed and resolved in the Stipulation are the result of negotiations among the parties to this proceeding and are not opposed by any party. The Commission has carefully reviewed the Stipulation and concludes that its adoption will result in rates that are just and reasonable to all customer classes.

For the reasons set forth in the foregoing paragraphs, the Commission concludes that the Stipulation provides a just and reasonable resolution of all the issues necessary to be addressed in this proceeding, subject to the submission and approval of rate schedules for implementation of the revenue reduction for DNCP. The Commission further concludes that the Stipulation will provide just and reasonable rates to all customer classes. The Commission finds and concludes that all of the provisions of the Stipulation, taken together, are reasonable under the circumstances of this proceeding and should be implemented. In so ruling, the Commission has not determined an authorized rate of return on either rate base or common equity for DNCP in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation is approved and DNCP is hereby authorized and directed to adjust its rates and charges in accordance with this Order and the Stipulation attached hereto as Exhibit A, effective as directed by further order of the Commission;

2. That in order to comply with ordering paragraph 1 of this Order, DNCP shall file for Commission approval five (5) copies of rate schedules designed to produce a reduction of $12,000,000 in annual non-fuel base revenue in accordance with the rate design guidelines contained in the Stipulation, accompanied by computations showing the level of revenue that will be produced by the rates for each schedule and a proposed customer notice; that this filing shall include the amended service agreement between DNCP and Nucor and revised Schedule NS for Commission approval as required by the Stipulation; that DNCP shall make this rate schedule compliance filing within 10 business days from the date of this Order;

3. That, upon Commission approval of the filings set forth in ordering paragraph 2 of this Order, DNCP shall make the approved rates effective for service consistent with the terms of the Stipulation;

4. That 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;

5. That, during the Rate Change Moratorium Period and afterwards, DNCP will continue to be subject to Commission Rule R8-27, including the Uniform System of Accounts adopted pursuant to that Rule, all other applicable accounting requirements and practices of the Commission, and Statement of Financial Accounting Standards No. 71 of the Financial Accounting Standards Board; and

6. That DNCP shall follow all of the other requirements of this Order and the attached Stipulation, including filing the revised ES-1 Reports and all additional filings, notice procedures, and other provisions set forth therein.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of March, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

sk031505.01

Exhibit A

DOCKET NO. E-22, SUB 412
DOCKET NO. E-100, SUB 56

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-22, SUB 412	)	
In the Matter of	)	
Dominion North Carolina Power –	)	
Investigation of Existing Rates and Charges	)	
	)	STIPULATION
DOCKET NO. E-100, SUB 56	)	AND
In the Matter of	)	AGREEMENT
Decommissioning Costs for Nuclear Power	)	
Plants Owned and Operated by Carolina	)	
Power and Light Company, Duke Power	)	
Company, and North Carolina Power	)	

Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), the Public Staff – North Carolina Utilities Commission (Public Staff), Carolina Industrial Group for Fair Utility Rates (CIGFUR I), and Nucor Steel – Hertford (Nucor), hereinafter collectively referred to as the Stipulating Parties, through counsel and pursuant to G.S. 62-69, respectfully submit the following Stipulation and Agreement for consideration by the Commission in the above-captioned dockets. The Stipulating Parties hereby stipulate and agree as follows:

1. Background.

A. On February 26, 1993, the Commission issued an order in Docket No. E-22, Sub 333, approving rates and charges designed to allow DNCP the opportunity to earn a return of 11.8% on the common equity component of its North Carolina retail rate base. The test period used in that case consisted of the twelve months ended December 31, 1991, updated for certain known changes based upon circumstances and events occurring up to the close of the hearing on January 20, 1993.

B. In 2003, the Public Staff conducted an informal review of DNCP's earnings and rate base, using a test period consisting of the twelve months ended December 31, 2002, updated for certain known changes occurring in 2003.

C. On January 29, 2004, the Public Staff filed a petition in Docket No. E-22, Sub 412, requesting that the Commission (i) institute an investigation into DNCP's existing rates and charges pursuant to G.S. 62-130(d), -133, -136(a), and -137 for the purpose of determining if they are unjust and unreasonable and, if so, determine the just and reasonable rates thereafter to be charged by DNCP; (ii) require DNCP to file a Rate Case Information Report (NCUC Form E-1) for the twelve months ended December 31, 2003; and (iii) require DNCP to appear before the Commission and show cause, in the form of prefiled testimony and exhibits, why its existing rates and charges should not be found unjust and unreasonable and reduced for service rendered thereafter.

D. DNCP responded to the Public Staff's petition on March 3, 2004.

E. On April 23, 2004, the Commission issued an order allowing the Public Staff's petition, instituting an investigation pursuant to G.S. 62-130(d), -133, and -136(a), declaring the matter to be a general rate case pursuant to G.S. 62-137, and setting the matter for investigation and hearing. The Commission established as a test period the twelve months ended December 31, 2003, with appropriate adjustments.

F. On June 24, 2004, the Commission issued an order consolidating matters in dispute regarding DNCP's nuclear decommissioning costs in Docket No. E-100, Sub 56, for investigation and hearing with DNCP's general rate case investigation in Docket No. E-22, Sub 412.

G. Pursuant to Commission order, on September 24, 2004, DNCP filed its Rate Case Information Report (NCUC Form E-1) based on test period data, including estimated adjustments through the year 2004, together with testimony of M. Stuart Bolton, Craig S. Ivey, Sunil Maheshwari, Charles A. Stadelmeier, and James H. Vander Weide. DNCP's filing supported a non-fuel base rate increase of $10.8 million, although DNCP did not propose to increase its rates in this proceeding. Subsequently, the Public Staff, CIGFUR I, and Nucor conducted substantial discovery on DNCP, and on January 24, 2005, the Public Staff filed the testimony and exhibits of Karyl J. Crean, Randy T. Edwards, Kennie D. Ellis, John R. Hinton, Thomas S. Lam, Howard M. Lowdermilk, Michael C. Maness, and James S. McLawhorn, supporting a non-fuel base rate decrease of approximately $23.8 million, and Nucor filed the testimony and exhibits of Dennis W. Goins and J. Bertram Solomon supporting a reduction of

DNCP's non-fuel revenue requirement. Thereafter, DNCP propounded discovery to the Public Staff and Nucor.

H. As a result of negotiations subsequent to the filing of testimony by the Public Staff and Nucor and prior to the date on which DNCP was scheduled and planned to file its rebuttal testimony, the Stipulating Parties were able to arrive at a settlement, the terms of which are set forth in the following sections of this Stipulation and Agreement. The Stipulating Parties agree to an annual non-fuel base rate reduction amount of $12,000,000, which the Stipulating Parties believe represents an appropriate resolution of the contested matters in this proceeding and will result in just and reasonable rates hereafter to be charged by DNCP, without a determination of each matter presented in the pre-filed direct testimonies of the Stipulating Parties related to rate base, operating revenues and expenses, and rate of return. The Stipulating Parties further agree as part of this Stipulation and Agreement to the other terms set forth herein.

2. **Rate Reduction.**

A. DNCP will adjust its North Carolina retail tariffs to produce a net decrease of $12,000,000 in non-fuel annual revenue from its North Carolina retail operations.

B. The twelve months ended December 31, 2003, non-fuel base revenue, including the effects of weather, customer growth, and increased usage updated through October 31, 2004, under present rates and the revenue decrease by customer class will be as follows:

Customer Class	Total Non-Fuel Base Revenue	Base Revenue Decrease
Residential	$107,790,118	($6,674,856)
Small General Service	44,069,607	(3,233,415)
Large General Service	19,658,381	(1,508,525)
NS	12,290,109	0
6VP	19,966,617	(577,267)
Outdoor & Street Lights	4,111,510	0
Traffic Lights	89,197	(5,937)
NC Retail	**$207,975,539**	**($12,000,000)**

C. To achieve the annual revenue decrease to North Carolina non-fuel retail revenues of $12,000,000, the number of billing units (end-of-period customers and megawatt-hour usage) will be as recorded through the test period for the twelve-months ended December 31, 2003, including the effects of weather, customer growth, and increased usage updated through October 31, 2004, as referred to in the table below.

Customer Class	EOP Customers	Booked MWh	Adjustment To MWh	Total Adjusted MWh
Residential	97,151	1,416,740	93,334	1,510,074
Small General Service	17,159	746,806	29,943	776,749
Large General Service	90	456,795	18,685	475,480
NS	1	703,341	112,662	816,003
6VP	6	528,095	65,765	593,860
Outdoor & Street Lights	12,277	23,084	324	23,408
Traffic Lights	206	1,360	(171)	1,189
NC Retail	**126,890**	**3,876,221**	**320,542**	**4,196,763**

Rates will be designed to ensure that no customer's monthly bill will increase. In the event that rounding is required, it will be applied in such a way that a non-fuel revenue decrease of at least $12,000,000 is produced. DNCP may increase its Service Connection Charge based on cost increases to produce additional annual revenue of approximately $373,000, provided that a corresponding decrease in revenue is distributed proportionately among customer classes in addition to the base revenue decreases shown in paragraph 2.B. above.

D. Within ten business days of an order accepting this Stipulation and Agreement, DNCP will file for Commission approval five copies of rate schedules designed to produce the $12,000,000 decrease in annual non-fuel base revenue in accordance with the rate design guidelines contained herein. The rate schedules will be accompanied by computations showing the level of revenue that will be produced by the rates for each schedule.

E. The effective date of the rate change (Effective Date) will be April 1, 2005, provided the Commission issues an order approving the rate schedules (the Approval Order), as submitted pursuant to paragraph 2.D. above, by March 18, 2005. In the event the Approval Order is issued later than March 18, 2005, the Effective Date will be modified accordingly by the difference between the number of business days between March 18, 2005, and the date of the Approval Order.

F. DNCP will give appropriate notice of the approved rate decrease by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle after the Effective Date of the rate change. DNCP will submit a proposed customer notice to the Commission for review and approval before it is mailed to customers.

3. **Rate Change Moratorium.**

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 or (2) to flow through the effects of changes in federal or state income tax law or changes in the gross receipts tax rate applicable to DNCP. None of the Stipulating Parties will initiate any proceeding which seeks to increase or decrease DNCP's non-fuel retail electric rates during the Rate Change Moratorium Period other than to initiate a proceeding under exception (2) above. In any proceeding addressing DNCP's base rates during the Rate Change Moratorium Period, the Stipulating Parties agree to support and defend the terms of this Stipulation and Agreement.

B. DNCP will not record any regulatory accounting deferrals not previously authorized by the Commission for any changes in costs incurred or revenues realized during the Rate Change Moratorium Period except, with Commission approval, on the grounds that such deferral is necessary to address pronouncements of entities authorized to set accounting standards (e.g., the Financial Accounting Standards Board).

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.

(2) During the Rate Change Moratorium Period and afterwards, DNCP will continue to be subject to Commission Rule R8-27, including the Uniform System of Accounts adopted pursuant to that Rule, all other applicable accounting requirements and practices of the Commission, and Statement of Financial Accounting Standards No. 71 of the Financial Accounting Standards Board.

4. **Base Fuel Factor.**

A. The base fuel factor included in DNCP's base rates will be 1.647¢/kWh, excluding gross receipts tax, or 1.701¢/kWh, including gross receipts tax, which is the same as the fuel factor approved in DNCP's most recent fuel charge adjustment proceeding, Docket No. E-22, Sub 422, pursuant to G.S. 62-133.2.

B. The methods and procedures to be used for calculating the fuel factor in future fuel charge adjustment proceedings will be the same as those followed in Docket No. E-22, Sub 422, except that the methodology for normalizing kWh sales for weather will be as follows:

(1) Ten years of monthly sales per customer will be regressed against the average number of billing days in a month, weather variables such as heating degree days and cooling degree days (adjusted on a billing cycle basis), time terms, monthly dummy variables, interactive variables, and dummy variables to account for unusual events.

(2) Normal weather for DNCP's customer classes in its North Carolina service territory will be determined by averaging weather data only from the Raleigh, Roanoke Rapids, and Norfolk weather stations for the 30 most recent calendar years. Normal weather for customer classes in Virginia will be determined by averaging weather data from the Washington DC, Richmond and Norfolk weather stations for the 30 most recent calendar years.

(3) The sales for customer classes that are found to be weather insensitive in the regression analysis will only be normalized to account for the effects of unusual events.

5. **Cost of Service Studies.** DNCP's filed annual North Carolina retail cost of service studies will include two studies: a cost of service study using the Summer/Winter Peak and Average methodology and a study using the Summer/Winter Peak and Average methodology as recommended in the testimony of Public Staff witness McLawhorn which assigns no production plant to Schedule NS.

6. **Depreciation Rates.** DNCP's annual depreciation expense during the Rate Change Moratorium Period will be based on the depreciation rates reflected in DNCP's depreciation studies filed on December 13, 2002, in Docket No. E-22, Sub 406.

7. **Nuclear Decommissioning Costs.** Beginning with the Effective Date of the rate change pursuant to this Stipulation and Agreement, DNCP will discontinue recording and funding $1,843,000 of annual nuclear decommissioning expense for North Carolina retail jurisdictional purposes and, unless otherwise ordered by the Commission, will record a nuclear decommissioning expense of $0 during the Rate Change Moratorium Period. In no event will

DNCP record a nuclear decommissioning expense less than $0 or remove monies from the North Carolina retail decommissioning fund during the Rate Change Moratorium Period. For calendar year 2005, DNCP will record and fund a pro rata portion of $1,843,000, as of the Effective Date the rate change pursuant to this Stipulation and Agreement.

8. **Demand Side Management Cost Overrecoveries.** DNCP will record and amortize for North Carolina regulatory accounting purposes a regulatory liability and the related deferred income tax costs associated with North Carolina retail accumulated demand side management (DSM) cost overrecoveries. The regulatory liability, deferred income tax costs, and associated amortizations will be determined in accordance with the following criteria:

A. The principal component of the regulatory liability will be equal to the accumulated balance of North Carolina retail DSM overrecoveries as of the Effective Date of the rate change pursuant to this Stipulation and Agreement.

B. Pursuant to the October 20, 1992, Joint Stipulation between DNCP and the Public Staff and the Commission's Order approving that Joint Stipulation in Docket No. E-100, Sub 64, the accrued interest component of the regulatory liability will be equal to accrued interest on the accumulating principal component, calculated at an annual rate of 8.05%, beginning February 26, 1993, and continuing until the Effective Date of the rate change pursuant to this Stipulation and Agreement. Interest will be calculated as compounding at the end of each calendar year.

C. The sum of the principal and interest components will be recorded as a North Carolina retail regulatory liability as of the Effective Date of the rate change pursuant to this Stipulation and Agreement.

D. Deferred income tax costs related to the regulatory liability will be recorded as of the Effective Date of the rate change pursuant to this Stipulation and Agreement. The amount of the deferred income tax costs will be equal to the regulatory liability multiplied by 39.64264%.

E. The North Carolina retail regulatory liability and related deferred income tax costs will be amortized over a three-year period beginning on the Effective Date of the rate change pursuant to this Stipulation and Agreement.

F. DNCP will provide to the Public Staff for review the calculations of the principal and interest components of the regulatory liability and the related deferred income tax costs.

G. As of the Effective Date of the rate change pursuant to this Stipulation and Agreement, the DSM deferral procedure approved by the Commission in Docket No. E-100, Sub 64 will cease to be in effect.

9. **Alliance RTO and PJM Start-Up Costs and PJM Administrative Fees.**

A. As of the Effective Date of the rate change pursuant to this Stipulation and Agreement, DNCP will write off as a non-utility expense the North Carolina retail portion of any previously deferred Alliance RTO or PJM start-up costs, as well as any deferred or accrued carrying charges on such costs.

B. In the event the Commission approves DNCP's application to join PJM in Docket No. E-22, Sub 418, DNCP will record the PJM administrative fees that are incurred by DNCP for purposes of serving its North Carolina retail load during the Rate Change Moratorium Period in accordance with the Commission's order in that docket.

C. DNCP will not defer or seek approval from any federal or state governmental authority for deferral of the North Carolina retail portion of any RTO/ISO start-up costs or administrative fees incurred during the Rate Change Moratorium Period.

10. **Non-Utility Generation Contract Buyout Costs.** DNCP will record and amortize for North Carolina regulatory accounting purposes (a) regulatory assets related to the North Carolina retail portion of the above-market portion of its buyouts of the LG&E, Gordonsville, Mecklenburg, Multitrade, Commonwealth Atlantic, and Panda-Rosemary non-utility generation (NUG) contracts, and (b) related deferred income tax savings. The regulatory assets, deferred income tax savings, and associated amortizations will be determined in accordance with the following criteria:

A. A presumed recording of a regulatory asset for each buyout at the date of each closing, consisting of the North Carolina retail portion of the NUG contract buyout impairment charge, and related deferred income tax savings calculated at a rate of 39.64264%.

B. The amortization period will be the remaining life of the original or amended contract term and presumed to have begun as of the date of each closing.

C. Actual recording of regulatory assets as of the Effective Date of the rate change pursuant to this Stipulation and Agreement consisting of the unamortized balances of each presumed regulatory asset, and related deferred income tax savings, both extrapolated from the presumed amounts set forth in paragraph A. above amortized at the rate set forth in paragraph B. above.

D. Subsequent to the Effective Date of the rate change pursuant to this Stipulation and Agreement, actual amortization of the regulatory assets at the amortization rate set forth in paragraph B. above.

11. **Hurricane Isabel Repair and Restoration Expenses.** For North Carolina regulatory accounting purposes, DNCP will record and amortize a regulatory asset and the related deferred income tax savings associated with the North Carolina retail portion of Hurricane Isabel repair and restoration expenses. The regulatory asset, deferred income tax savings, and associated amortizations will be determined in accordance with the following criteria:

A. A presumed recording at September 18, 2003, of a regulatory asset consisting of the unamortized North Carolina retail Hurricane Isabel expenses of $13,552,000, and related deferred income tax savings of $5,372,000.

B. An amortization period presumed to have begun in mid-September of 2003.

C. Presumed amortization of the deferred North Carolina retail Hurricane Isabel expenses in the amount of $226,000 per month and the related deferred income tax savings in the amount of approximately $90,000 per month.

D. A presumed unamortized balance at October 31, 2004, of North Carolina retail Hurricane Isabel expenses of $10,501,000, and the related deferred income tax savings of $4,157,000.

E. Actual recording of a regulatory asset as of the Effective Date of the rate change pursuant to this Stipulation and Agreement consisting of the unamortized balances of Hurricane Isabel expenses and related deferred income tax savings, both extrapolated from the presumed October 31, 2004, unamortized balances set forth in paragraph D. above at the amortization amounts set forth in paragraph C. above.

F. Subsequent to the Effective Date of the rate change pursuant to this Stipulation and Agreement, actual amortization of the deferred North Carolina retail Hurricane Isabel expenses in the amount of approximately $226,000 per month and related deferred income tax savings in the amount of approximately $90,000 per month.

12. **ES-1 Reports.** If directed to do so by the Commission, DNCP will provide the Commission and the Public Staff with revised ES-1 reports, recalculated to take into account the presumed regulatory assets, deferred income taxes, and amortizations set forth in paragraphs 10 and 11 above.

13. **Service Quality.** Within 60 days of the date of an order approving this Stipulation and Agreement, DNCP will meet with the Public Staff to begin good faith negotiations regarding its procedures for providing electric service with the intent to develop, as necessary, procedures for responding to requests for new and temporary electric service in an appropriate and timely manner. In the event such negotiations do not produce agreement on all issues within six months from the date of the order approving this Stipulation and Agreement, DNCP and the Public Staff agree that the issue(s) on which the negotiations have not produced agreement shall be presented to the Commission for resolution.

14. **Rate Schedule NS.** DNCP and Nucor have agreed to amend the *Agreement for Electric Service between Nucor Corporation and Virginia Electric and Power Company, doing business in North Carolina as North Carolina Power* (as amended May 30, 2002) ("Service Agreement") and to revise Schedule NS accordingly. The revised Schedule NS and the Service Agreement as amended will be filed with the Commission. Approval of the revised Schedule NS will be required in accordance with the orders and rules of the Commission. The Service Agreement and Schedule NS shall not be modified or terminated prior to October 31, 2010, without the written consent of Nucor.

15. **Rate Schedule 6VP.** Schedule 6VP will be revised to eliminate the current termination date of December 31, 2006. The proposed Schedule 6VP will be filed with the Commission for approval.

16. **Agreement to Support Settlement; Non-Waiver.** The Stipulating Parties will support this Stipulation and Agreement in any proposed order or brief and in any hearing before the Commission; provided, however, that the settlement of any issues pursuant to this Stipulation

and Agreement will not be cited as precedent by any of the Stipulating Parties in any other proceeding or docket before this Commission. The provisions of this Stipulation and Agreement do not necessarily reflect any position asserted by any of the Stipulating Parties. Rather, they reflect a settlement among the Stipulating Parties as to all issues, and no Stipulating Party waives the right to assert any position in any future docket before the Commission.

17. **Attorney General's Office.** The Attorney General's Office has advised the Stipulating Parties that, while it does not join in this Stipulation and Agreement, it does not object to the Stipulation and Agreement and will not appeal any order of the Commission approving and implementing the Stipulation and Agreement.

18. **Introduction of Testimony and Waiver of Cross-Examination.** The Stipulating Parties agree that all pre-filed testimony and exhibits may be introduced into evidence without objection, and the Stipulating Parties waive their respective rights to cross-examine all witnesses with respect to such pre-filed testimony and exhibits. If, however, questions should be asked by any person who is not a Stipulating Party, including a member of the Commission, the Stipulating Parties may present testimony and exhibits to respond to such questions and cross-examine any witnesses with respect to such testimony and exhibits, provided that such testimony, exhibits, and cross-examination are not inconsistent with this Stipulation and Agreement.

19. **Stipulation and Agreement Binding Only if Accepted in Its Entirety.** This Stipulation and Agreement is the product of give-and-take negotiations, and no portion of this Stipulation and Agreement will be binding on the Stipulating Parties unless the entire Stipulation and Agreement is accepted by the Commission. If the Commission rejects the Stipulation and Agreement in whole or in part, DNCP reserves its right to submit rebuttal testimony, the filing date for which was suspended in order for the Stipulating Parties to pursue a settlement in this proceeding.

The foregoing is agreed and stipulated to, this the 8th day of March, 2005.

Dominion North Carolina Power
/s/
David G. Shuford
Vice President – Regulation

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

Carolina Industrial Group for Fair Utility Rates
/s/
Ralph McDonald

Nucor Steel – Hertford
/s/
Joseph W. Eason

DOCKET NO. E-22, SUB 428

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Dominion North Carolina Power for Authority	)	ORDER APPROVING
to Adjust its Electric Rates Pursuant to North Carolina	)	FUEL CHARGE
General Statute 62-133.2 and North Carolina Utilities	)	ADJUSTMENT
Commission Rule R8-55	)	

HEARD: Tuesday, November 8, 2005, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; and Commissioners James Y. Kerr, II, and Lorinzo L. Joyner

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

For Nucor Steel - Hertford:

Christopher J. Blake, Nelson, Mullins, Riley & Scarborough, LLP, 4140 Parklake Avenue, GlenLake One, Suite 200, Raleigh, North Carolina 27612

For Carolina Industrial Group for Fair Utility Rates I:

Anna Baird Choi, Bailey and Dixon, LLP, P. O. Box 1351, Raleigh, North Carolina 27602-1351

For the Using and Consuming Public:

James D. Little, 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

BY THE COMMISSION: G.S. 62-133.2 requires the North Carolina Utilities Commission to hold a hearing annually for each electric utility engaged in the generation and production of electric power by fossil or nuclear fuel for the purpose of determining whether an increment or decrement rider is required to reflect actual changes in the cost of fuel and the fuel component of purchased power over or under the base fuel component established in the utility's 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 21, 2004, in Docket No. E-22, Sub 422.

On September 9, 2005, Dominion NC Power filed the testimony and exhibits of A. Brian Cassada, Charles A. Stadelmeier and Jack E. Streightiff 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 North Carolina Utilities Commission Rule R8-55(d).

On September 13, 2005, the Commission issued an Order Scheduling Hearing and Requiring Public Notice.

Carolina Industrial Group for Fair Utility Rates I and Nucor Steel-Hertford (Nucor), a division of Nucor Corporation, filed Petitions to Intervene on September 20, 2005, which were allowed by Commission Orders issued September 23, 2005. The Attorney General filed Notice of Intervention pursuant to G.S. 62-20 on October 12, 2005.

On October 28, 2005, the Public Staff filed the affidavits of Thomas S. Lam, Engineer with the Public Staff's Electric Division, and Randy T. Edwards, Staff Accountant with the Public Staff's Accounting Division.

On November 3, 2005, the Company filed its Affidavit of Publication for this proceeding.

At the hearing, the prefiled direct testimony and exhibits of the Company's witnesses and the affidavits of the Public Staff's witnesses were admitted into evidence. No public witnesses appeared at the hearing.

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

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2005.

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

4. The Company did not determine if the purchase and sale transactions between it and PJM Interconnection, LLC (PJM) for the months of May and June 2005, which were contained in the test period used in this fuel proceeding, were in compliance with Ordering

Paragraph 1(e) of the Commission Order dated April 19, 2005, in Docket No. E-22, Sub 418. Estimates determined appropriate by the Company were used.

5. The test period per book system sales are 77,183,802 MWh.

6. The test period per book system generation is 81,344,750 MWh, and is categorized as follows:

Generation Type	MWh
Coal	32,234,442
Combustion Turbine	3,789,018
Heavy Oil	2,780,746
Nuclear	26,661,136
Hydro	3,005,571
Pumped Storage (Pumping)	(2,816,628)
Power Transactions	
NUG	10,770,935
Other	5,686,893
Sales for Resale	(767,363)

7. The nuclear capacity factor appropriate for use in this proceeding is 91.8%, which is the expected nuclear capacity factor for the year ending December 31, 2006.

8. The adjusted test period system sales for use in this proceeding are 79,541,719 MWh.

9. The adjusted test period system generation for use in this proceeding is 83,817,192 MWh, and is categorized as follows:

Generation Type	MWh
Coal	34,132,470
Combustion Turbine	4,012,146
Heavy Oil	2,944,464
Nuclear	25,879,605
Hydro	3,005,571
Pumped Storage (Pumping)	(2,816,628)
Power Transactions	
NUG	11,405,168
Other	6,021,759
Sales for Resale	(767,363)

10. The appropriate fuel prices and fuel expenses for use in this proceeding are:

A. $19.22/MWh for coal;
B. $4.28/MWh for nuclear;
C. $50.68/MWh for heavy oil;
D. $82.25/MWh for internal combustion turbine fuel;
E. $27.75/MWh for the fuel price of other power transactions; and
F. A zero fuel price for hydro and pumped storage.

11. The adjusted test period system fuel expense for use in this proceeding is $1,461,639,153.

12. The proper fuel factor for this proceeding is 1.838¢/kWh, excluding gross receipts tax, or 1.898¢/kWh, including gross receipts tax.

13. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 60% of the energy portion of the purchase price is reasonable for use in this proceeding.

14. The appropriate North Carolina jurisdictional test period fuel expense under-recovery for use in this proceeding is $7,577,888. The adjusted North Carolina jurisdictional test period sales for use in this proceeding are 4,301,434 MWh.

15. The appropriate Experience Modification Factor (EMF) for purposes of this proceeding is an increment of 0.176¢/kWh, excluding gross receipts tax, or 0.182¢/kWh, including gross receipts tax.

16. The final net fuel factor to be billed to Dominion NC Power's North Carolina retail customers during the 2006 fuel clause billing period is 2.014¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 1.838¢/kWh and the EMF increment of 0.176¢/kWh, or 2.080¢/kWh, including gross receipts tax, consisting of the prospective fuel factor of 1.898¢/kWh and the EMF increment of 0.182¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Dominion NC Power's witness Cassada testified that the Company has not yet performed a detailed analysis evaluating what may have happened had Dominion NC Power not joined PJM Interconnection, LLC (PJM), as necessitated by Ordering Paragraph 1(e) of the Commission's Order dated April 19, 2005 in Docket No. E-22, Sub 418. According to witness Cassada, a study of this nature is a significant undertaking and, due to the short time period since Dominion NC Power joined PJM on May 1, 2005, the study was not completed in time for this fuel proceeding. Witness Cassada also testified that the Company is proposing that in the next fuel case, to be filed in September 2006, any adjustments necessary to comply with Ordering Paragraph 1(e) would cover the fourteen-month period May 1, 2005, through June 30, 2006, rather than the twelve-month test period for that fuel case of July 1, 2005, through June 30, 2006. Further, he testified that any such adjustments related to May and June of 2005, if warranted as a result of the study, would be incorporated with interest into the EMF in that case.

Public Staff witness Edwards stated in his affidavit that the Public Staff agrees with the Company's plan to perform a study to determine what fuel costs would have been incurred had it not joined PJM. However, the Public Staff is concerned that the limited period of time between the filing and the hearing of the 2006 fuel case would not provide sufficient time for an adequate review of the Company's study. Witness Edwards said the Public Staff had discussed its concerns with the Company, and it is the Public Staff's understanding that the Company is agreeable to updating the Public Staff with regard to the nature and progress of the study on a regular and frequent basis and to provide the Public Staff with information regarding the study in accordance with the following timetable:

(1) No later than February 15, 2006 – Meet with the Public Staff to discuss the study.
(2) No later than March 15, 2006 – Provide the Public Staff with the results of the study for the months of May through December 2005.
(3) No later than August 15, 2006 – Provide the Public Staff with the results of the study for the months of January through June 2006.

Witness Edwards stated that the Public Staff recommends that this timetable be incorporated into the Commission's order in this proceeding. According to witness Edwards, the Public Staff also wishes to note that, given the complexity of the Company's transactions with PJM, the Public Staff plans to continue during the coming year to review the appropriate treatment of fuel costs pursuant to all of the requirements of the Commission Order dated April 19, 2005 in Docket No. E-22, Sub 418.

The Commission concludes that updates regarding the nature and progress of the study on a regular and frequent basis and the timetable for the Company providing information to the Public Staff agreed to by Dominion NC Power and the Public Staff are reasonable and appropriate for this fuel proceeding.

At the hearing, counsel for the Public Staff stated that the other intervenors, which include the Attorney General, North Carolina Department of Justice, Carolina Industrial Group for Fair Utility Rates I, and Nucor Steel-Hertford (intervenors), had requested to participate in meetings between Dominion NC Power and the Public Staff related to the Company's study and to receive copies of the study as outlined in the timetable. According to the Joint Proposed Order filed on December 1, 2005, Dominion NC Power and the Public Staff have agreed to include the intervenors in meetings regarding the study and to provide them copies of the study as outlined in the timetable agreed to by the Company and the Public Staff.

The Commission concludes that including the intervenors in discussions and meetings between Dominion NC Power and the Public Staff and providing the intervenors with copies of the study is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

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

Witness Streightiff testified that the test period per book system sales were 77,183,802 MWh and witness Stadelmeier testified that the test period per book system generation was 81,344,750 MWh. The test period per book system generation is categorized as follows:

Generation Type	MWh
Coal	32,234,442
Combustion Turbine	3,789,018
Heavy Oil	2,780,746
Nuclear	26,661,136
Hydro	3,005,571
Pumped Storage (Pumping)	(2,816,628)
Power Transactions	
NUG	10,770,935
Other	5,686,893
Sales for Resale	(767,363)

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

Company witness Stadelmeier and Public Staff witness Lam testified that the Company achieved a system nuclear capacity factor of 93.9% for the test period, which exceeded the most recent (1999-2003) NERC five-year average nuclear capacity factor for pressurized water reactor units of 86.1%. Witness Stadelmeier normalized the system nuclear capacity factor to a level of 91.8%, which is the expected nuclear capacity factor for the twelve months ending December 31, 2006. Witness Lam testified that the 91.8% normalized nuclear capacity factor should be more representative of the nuclear performance the Company can reasonably be expected to achieve during the period when the fuel factor established in this proceeding is in effect than either the actual test period capacity factor or the NERC five-year average.

Based upon the evidence, the Commission concludes that the test period per book system sales and generation proposed by the Company are reasonable and appropriate for use in this proceeding and that the 91.8% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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

Witness Streightiff testified that the Company's system sales for the twelve months ended June 30, 2005 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 2,357,917 MWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 51,973 MWh, 472,763 MWh and 1,262,092 MWh, respectively, and adjustments for customer growth and weather normalization of 535,590 MWh and 35,499 MWh, respectively, 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 for use in this proceeding. Therefore, the Company's adjusted system sales for the twelve months ended June 30, 2005 were 79,541,719 MWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

Company witness Streightiff presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2005, due to weather normalization, customer growth, and increased usage of 2,472,384 MWh to arrive at witness Stadelmeier's adjusted generation level of 83,817,192 MWh. Public Staff witness Lam reviewed and accepted witness Streightiff's adjustment to per book MWh generation for the 12-month period ended June 30, 2005, due to weather normalization, customer growth and increased usage. Witness Lam also accepted witness Stadelmeier's adjusted generation level of 83,817,192 MWh, which includes various categories of generation, as follows:

Generation Type	MWh
Coal	34,132,470
Combustion Turbine	4,012,146
Heavy Oil	2,944,464
Nuclear	25,879,605
Hydro	3,005,571
Pumped Storage (Pumping)	(2,816,628)
Power Transactions	
NUG	11,405,168
Other	6,021,759
Sales for Resale	(767,363)

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

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

Witness Stadelmeier testified that the Company's proposed fuel factor is based on June 2005 fuel prices as follows: 1) coal price of $19.22/MWh; 2) nuclear price of $4.28/MWh; 3) heavy oil price of $50.68/MWh; 4) internal combustion turbine price of $82.25/MWh; 5) other power transactions price of $27.75/MWh; and 6) hydro and pumped storage priced at zero. Witness Lam accepted witness Stadelemeier's fuel prices.

In the absence of any evidence to the contrary, the Commission concludes that the fuel prices recommended by Company witness Stadelmeier and accepted by Public Staff witness Lam are reasonable and appropriate for use in this proceeding.

Company witness Stadelmeier stated in his testimony that he calculated the level of normalized fuel expenses by multiplying the normalized generation amounts for the Company's generating units by actual June 2005 fuel prices. The level of test period normalized fuel expense resulting from this calculation is $1,461,639,153. Public Staff witness Lam accepted this level of test period normalized fuel expense.

Exhibit No. JES-1, Schedule 3, explains witness Streightiff's calculation of a proposed fuel factor for the twelve months ended December 31, 2006, derived by dividing the normalized fuel expense of $1,461,639,153 by the adjusted level of test period system MWh sales of 79,541,719 MWh. This calculation results in a proposed fuel factor of 1.838¢/kWh, excluding gross receipts tax, and 1.898¢/kWh, including gross receipts tax. When this fuel factor is reduced by the base fuel component approved in the Company's most recent general rate case of 1.647¢/kWh, the resulting fuel cost rider (Rider A) is 0.191¢/kWh, excluding gross receipts tax, and 0.197¢/kWh, including gross receipts tax.

The Commission concludes that adjusted test period fuel expenses of $1,461,639,153 and the fuel cost rider increment of 0.191¢/kWh, excluding gross receipts tax, or a 0.197¢/kWh increment, including gross receipts tax, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the affidavit of Public Staff witness Edwards. Witness Edwards stated that, during the test period, Dominion NC Power purchased power from a number of power marketers and other suppliers that did not provide it with the actual fuel costs associated with those purchases. He stated that a similar situation has occurred in each of the fuel proceedings for Carolina Power & Light Company (CP&L), Duke Power, and Dominion NC Power since 1996.

For purposes of determining Dominion NC Power's EMF in this proceeding, he recommended that the Commission adopt the application of a 60% ratio to the total energy cost of purchases from power marketers and other sellers who do not provide Dominion NC Power with actual fuel costs. To determine this ratio, the Public Staff performed a review of the fuel component of off-system sales made by Duke Power, Dominion NC Power, and Progress Energy

Carolinas, Inc., which are set forth in each of the utilities' Monthly Fuel Reports, for the twelve months ended December 31, 2004. Witness Edwards 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 each 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, and 2004.

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 58.66% to 61.74%, as set forth in Edwards Exhibit I. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel ratio should be 60%.

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 Power's 1996 fuel proceeding, Docket No. E-7, Sub 575, 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 his affidavit, Public Staff 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 proxy fuel cost as described above. He stated that, 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 ratio inherent in the purchases made by the utilities is similar to the ratio exhibited by the utilities' sales. Additionally, the information used by the Public Staff to determine the off-system sales fuel ratio was derived from the Monthly Fuel Reports filed with the Commission. Witness Edwards stated that this information is reasonably reliable. Finally, witness Edwards stated that the Public Staff is unaware of any alternative information currently available concerning the fuel component of the marketers' sales made to utilities. Therefore, according to witness Edwards, the methodology used in past Marketer Stipulations and in the analysis for this proceeding meets the criteria set forth in the 1996 Duke Power order.

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 Power 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 Edwards 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 cost ratio exhibited by the utilities' sales is similar to the ratio 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 affidavit of witness Edwards, 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 Power 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 ratio to be used in this case.

As part of the most recent review, the Public Staff analyses of off-system sales information resulted in fuel percentages ranging from 58.66% to 61.74%. Based on these analyses, the Public Staff concluded that 60% is an appropriate and reasonable fuel ratio for purposes of this proceeding.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use the 60% 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 FINDINGS OF FACT NOS. 14 & 15

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Cassada and Streightiff and the affidavits of Public Staff witnesses Edwards and Lam.

Company witness Cassada testified that the Company under-collected its fuel expenses by $7,451,825 during the test period ending June 30, 2005. This was adjusted in witness Streightiff's testimony to $7,682,148, to reflect an adjustment for purchases subject to the 60% fuel proxy ratio recommended by Public Staff witness Edwards. Company witness Streightiff testified that the adjusted North Carolina retail test period sales are 4,325,395 MWh.

Public Staff witness Edwards investigated the Experience Modification Factor (EMF) to determine whether the Company properly determined its fuel costs and MWh sales during the test period. Witness Edwards' investigation resulted in decreasing the Company's North Carolina retail fuel expense by an amount of $104,260. This adjustment reduced the test period fuel under-recovery from $7,682,148 to $7,577,888. Witness Edwards' investigation also revealed that the Company's North Carolina retail sales were overstated by 23,961 MWh for the test period and should be reduced from 4,325,395 MWh to 4,301,434 MWh.

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."

The $7,577,888 under-recovered fuel expense can thus be divided by the adjusted North Carolina retail sales of 4,301,434 MWh to arrive at an EMF increment of 0.176¢/kWh, excluding gross receipts tax, or 0.182¢/kWh, including gross receipts tax. The Commission concludes that this EMF increment is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is cumulative and is contained in the testimony and exhibits of Company witnesses Cassada and Streightiff and the affidavits of Public Staff witnesses Edwards and Lam.

Based upon our prior findings in this proceeding, the Commission finds that the final net fuel factor, including gross receipts tax, approved for usage in this case is 2.080¢/kWh.

The fuel factor is determined as follows:

Normalized System Fuel Expense	$1,461,639,153
System kWh Sales at Sales Level	79,541,718,639
Test Year North Carolina Retail Fuel Under-recovery	$7,577,888
North Carolina Retail kWh Sales At Sales Level	4,301,433,892
Base Fuel Component Approved in Docket No. E-22, Sub 412 (¢/kWh)	1.647
Gross Receipts Tax Factor	1.03327

Fuel Cost Rider A (excluding gross receipts tax) =
[$1,461,639,153/79,541,718,639kWh] - 1.647¢/kWh = 0.191¢/kWh

Fuel Cost Rider A (including gross receipts tax) =
0.191¢/kWh x 1.03327 = 0.197¢/kWh

Fuel Cost Rider B (excluding gross receipts tax) =
[$7,577,888/4,301,433,892kWh] = 0.176¢/kWh

Fuel Cost Rider B (including gross receipts tax) =
0.176/¢kWh x 1.03327 = 0.182¢/kWh

	Effective 1/1/2006 (¢/kWh Including Gross Receipts Tax)
Base Fuel Factor	1.701
EMF/Rider B	.182
Fuel Cost Rider A	.197
FINAL FUEL FACTOR	2.080

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2006, 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 0.191¢/kWh, excluding gross receipts tax, or 0.197¢/kWh, including gross receipts tax;

2. That an EMF Rider increment (Rider B) of 0.176¢/kWh, excluding gross receipts tax, or 0.182¢/kWh, including gross receipts tax, shall be instituted and remain in effect for usage from January 1, 2006, until December 31, 2006;

3. That Dominion NC Power shall update the Public Staff with regard to the nature and progress of the Company's PJM study to determine compliance with Ordering Paragraph 1(e) of the Commission's Order dated April 19, 2005, in Docket No. E-22, Sub 418, on a regular and frequent basis, and that Dominion NC Power shall adhere to the following timetable:

(1) No later than February 15, 2006 – Meet with the Public Staff to discuss the study,
(2) No later than March 15, 2006 – Provide the Public Staff with the results of the study for the months of May through December 2005,
(3) No later than August 15, 2006 – Provide the Public Staff with the results of the study for the months of January through June 2006;

4. That the Public Staff shall invite intervenors to meetings, including telephone conferences, with Dominion NC Power regarding the Company's PJM study, with the understanding that, if Dominion NC Power requires non-disclosure agreements, they will be signed by the intervenors prior to their participation;

5. That the Public Staff shall provide intervenors with copies of the PJM study as outlined in the timetable agreed to by Dominion NC Power and the Public Staff, with the understanding that, if Dominion NC Power requires non-disclosure agreements, they will be signed by the intervenors prior to the intervenors receiving any information;

6. 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; and

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

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

mr121905.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 428

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 19, 2005, after public hearing, approving a $5,677,893 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, 2006. 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, 2005, 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 $1.32 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

mr121905.01

DOCKET NO. E-34, SUB 36

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER APPROVING
Application by New River Light & Power	)	RATE INCREASE
Company for Approval of a Rate Increase	)	SUBJECT TO REFUND
to Pass Through an Increase in the Cost	)	AND REQUIRING
of Purchased Power	)	PUBLIC NOTICE

BY THE COMMISSION: On October 26, 2005, New River Light & Power Company (New River) filed a request with the Commission to adjust its base rates for usage on and after

January 1, 2006, in order to pass through to its customers the increased cost of purchased power from its wholesale supplier, Blue Ridge Electric Membership Corporation (BREMCO). New River recently completed negotiations with BREMCO for total energy requirements through December 31, 2008. The negotiations resulted in a wholesale rate increase for purchased power on and after January 1, 2006 of approximately $670,541.

New River proposes to pass the increase along to its customers as a uniform across-the-board increase in the kWh charge. New River's current base rates, as approved by the Commission in Docket No. E-34, Sub 35, will be adjusted to include the increased cost of purchased power of $.003101 per kWh.

The additional revenue produced by the increase to New River's customers will be the same as the additional cost of purchased power from BREMCO, adjusted for the effects of Gross Receipts Tax and the Utility Regulatory Fee. Thus, the Commission finds that the base rate adjustment will have the same effect as a fuel charge adjustment and should not affect the rate of return.

New River also requested authority to discontinue its $2.50 per device per month energy credit for load management approved in Docket No. E-34, Sub 24. This credit was applicable to electric utility service provided under Schedule R and G. The North Carolina Electric Membership Corporation (NCEMC) canceled this program in April 2000 and no longer provides the credit to New River. However, New River has continued to provide the credit to its customers. New River proposes to continue the credit for 90 days after January 1, 2006, while the devices are being disabled.

At the Commission's Regular Staff Conference on November 7, 2005, the Public Staff stated that it had reviewed New River's calculations of both the increase in wholesale power costs and the proposed increase in retail rates and determined that the proposed adjustment was consistent with previous New River pass through requests approved by the Commission. The Public Staff also did not object to the discontinuation of the load management credit as requested by New River.

The Commission, therefore, concludes that the proposed pass through should be approved, subject to refund of any amounts subsequently found to be unjust or unreasonable upon protest and hearing. The Commission also concludes that New River should be allowed to discontinue its load management credit program.

IT IS, THEREFORE, ORDERED as follows:

1. That New River is hereby authorized to adjust its base rates by $.003101 per kWh effective with all usage on and after January 1, 2006, in order to pass through to its customers the increased costs of purchased power from its supplier as described herein, subject to refund of any amounts subsequently found to be unjust and unreasonable should a hearing be held;

2. That, unless significant protests are received on or before December 30, 2005, the rate adjustment approved herein shall become final;

3. That New River shall file copies of its approved rates, modified herein, within 10 days of the date of this Order;

4. That the Notice to the Public attached as Appendix A be mailed by separate mail or bill insert by New River to all its customers, and that said Notice be mailed not later than 7 days after the date of this Order;

5. That the Notice to the Public be published by New River at its own expense in newspapers having general coverage in its North Carolina service area once a week for two consecutive weeks, the first Notice appearing not later than 7 days following the date of this Order and said Notice covering no less than one-quarter of a page; and

6. That New River is authorized to discontinue the load management credit approved in Docket No. E-34, Sub 24, as requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of November, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah110805.02

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 36

NOTICE TO THE PUBLIC

Notice is hereby given that New River Light & Power Company (New River) has requested the North Carolina Utilities Commission to approve an adjustment to its base rates for usage on and after January 1, 2006, to pass through to its customers the increased cost of purchased power from its supplier, Blue Ridge Electric Membership Corporation (BREMCO).

The amount of the base rate increase to New River's customers will be approximately 4.83%. The increase will be applied to New River's customers as a uniform increase to the kWh energy charge. The additional revenue produced by the increase will be the same as the increased cost of purchased power from BREMCO, adjusted for the effects of Gross Receipts Tax and the Utility Regulatory Fee.

The Commission has concluded that the base rate adjustment will have the same effect as a fuel charge adjustment and should not affect New River's rate of return. Therefore, the Commission has approved the rate adjustment and authorized New River to increase its base rates $.003101 per kWh effective with all usage on and after January 1, 2006, subject to refund of any amounts subsequently found to be unjust or unreasonable should a hearing be held. The

Commission may schedule a hearing to consider whether the proposed rate increase is just and reasonable if significant protests are received from customers of New River on or before December 30, 2005.

Persons desiring to protest the proposed rate increase or to intervene in this matter as formal parties of record must file an appropriate motion or petition under the Commission's Rules and Regulations not later than December 30, 2005. Persons desiring to present testimony or evidence at a hearing should so advise the Commission. Persons desiring to send written statements to inform the Commission of their position in the matter should address their statements to Geneva S. Thigpen, Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325. However, such written statements cannot be considered competent evidence unless those persons appear at a public hearing and testify concerning the information contained in their written statements. Unless significant protests are received on or before December 30, 2005, the rate increase shall become final.

The Public Staff is authorized by statute to represent the using and consuming public in proceedings before the Commission. Written statements to the Public Staff should include any information which the writer wishes to be considered by the Public Staff in its investigation of the matter, and such statements should be addressed to Robert P. Gruber, Executive Director, Public Staff 4326 Mail Service Center, Raleigh, North Carolina 27699-4326.

New River also requested permission to discontinue its energy credit of $2.50 per device per month for load management. The North Carolina Electric Membership Corporation (NCEMC) dropped this program in April 2000 and no longer provides the credit to New River. However, New River has continued to provide the credit to its customers. New River will continue the credit for 90 days after January 1, 2006, while the devices are being disabled. The Commission has concluded that New River should be allowed to discontinue the load management energy credit.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of November, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. E-22, SUB 418

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Authority to Transfer Functional Control of Transmission Assets to PJM Interconnection, LLC	)))))	ORDER APPROVING TRANSFER SUBJECT TO CONDITIONS

HEARD: Tuesday, October 26, 2004, at 9:30 a.m., Wednesday, January 19, 2005, at 9:00 a.m., Thursday, January 27, 2005, at 9:30 a.m., Friday, January 21, 2005, at 9:30 a.m., Wednesday, January 26, 2005, at 9:00 a.m., and Thursday, January 27, 2005, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Chair Jo Anne Sanford, and Commissioners J. Richard Conder, Robert V. Owens, Jr., Lorinzo Joyner, James Y. Kerr, II, and Michael S. Wilkins[1]

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

Edward L. Flippen, McGuireWoods LLP, 901 East Cary Street, Richmond, Virginia 23219

Michael C. Regulinski, Dominion Resources Services, Inc., 120 Tredegar Street, Richmond, Virginia 23219

John R. Lilyestrom, Hogan & Hartson, LLP, 555 Thirteenth Street, NW, Washington, D.C. 20004

For PJM Interconnection, LLC:

M. Gray Styers, Jr., Blanchard, Jenkins, Miller, Lewis, & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

Craig Glazer, PJM Interconnection, LLC, 1200 G Street, NW, Suite 600, Washington, D.C. 20005

Phillip Golden, PJM Interconnection, LLC, 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19043

[1] Commissioner Wilkins resigned from the Commission prior to decision-making in this proceeding.

For Carolina Industrial Group for Fair Utility Rates I and II:

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

For Carolina Utility Customers Association, Inc.:

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

For Duke Power, a Division of Duke Energy Corporation:

Jeffrey M. Trepel, Duke Energy Corporation, 422 South Church Street, Charlotte, North Carolina 28202

For North Carolina Eastern Municipal Power Agency:

Michael S. Colo, Poyner & Spruill L.L.P, 3600 Glenwood Avenue, Raleigh, North Carolina 27612

For Progress Energy Carolinas, Inc.:

Len S. Anthony, Deputy General Counsel - Regulatory Affairs, Progress Energy Service Company, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

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

Leonard Green, Assistant Attorney General, North Carolina Department of Justice, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001

BY THE COMMISSION: On April 2, 2004, Virginia Electric and Power Company, doing business in North Carolina as Dominion North Carolina Power (Dominion or the Company), filed with the Commission its Application pursuant to G.S. 62-111(a) for authority to transfer operational control of its transmission facilities located in the State of North Carolina to PJM Interconnection, LLC (PJM). Dominion's Application was accompanied by the testimony and exhibits of Harold Adams, Ronnie Bailey, Joseph E. Bowring, Andrew J. Evans, David F. Koogler, Paul D. Koonce, Gregory J. Morgan, Harold W. Payne, Jr., Robert B. Stoddard, William L. Thompson, and Richard A. Wodyka. Dominion also submitted draft agreements between itself and PJM and proposed revisions to Dominion's open access transmission tariff (OATT) reflecting the integration of Dominion's transmission system into PJM as PJM South.

By Order issued May 6, 2004, the Commission scheduled an evidentiary hearing to begin on October 26, 2004, in Raleigh, North Carolina; required petitions to intervene to be filed on or before July 30, 2004; required the Public Staff's and other Intervenors' testimony and exhibits to be filed on or before September 30, 2004; required rebuttal testimony, if any, to be filed on or before October 19, 2004; established discovery guidelines consistent with previously issued procedural orders; and required the Company to give public notice of the application and hearing. On August 17, 2004, Dominion filed its Affidavits of Publication pursuant to the Commission's Order.

PJM and the following additional parties filed timely notices or petitions and were allowed to intervene: Progress Energy Carolinas, Inc. (Progress), Carolina Utility Customers Association, Inc. (CUCA), Carolina Industrial Group for Fair Utility Rates (CIGFUR) I and II, Duke Power Company (Duke), North Carolina Electric Membership Corporation (NCEMC), Towns of Black Creek, Enfield, Lucama, Sharpsburg and Stantonburg (NC Towns), North Carolina Eastern Municipal Power Agency (NCEMPA), North Carolina Municipal Power Agency No. 1 (NCMPA), the Attorney General, and the Public Staff.

On September 15, 2004, the Commission issued an Order Revising Hearing Schedule establishing a more detailed hearing schedule for purposes of this proceeding.

On September 28, 2004, the Commission issued an Order Allowing Filing of Pre-Hearing Briefs establishing a schedule for the submission of pre-hearing briefs at the request of the Public Staff.

On September 30, 2004, CIGFUR I filed the testimony of Nicholas Phillips, Jr. and Progress filed the testimony of Kenneth R. Wilkerson. On October 1, 2004, the Public Staff filed the testimony and exhibits of Jack L. Floyd, Thomas E. Lam, James S. McLawhorn, Michael C. Maness, Dr. Matthew J. Morey, Darlene P. Peedin, and Dr. Alan Rosenberg. On October 1, 2004, Duke filed a letter with the Commission stating its position in this proceeding.

On October 5, 2004, the Federal Energy Regulatory Commission (FERC) issued its Order Establishing PJM South, Subject to Conditions. In that separate but related proceeding, FERC approved the Company's and PJM's joint application (FERC Application) pursuant to Section 205 of the Federal Power Act (FPA) for the Company to join PJM. The FERC Application was filed on May 11, 2004, and docketed as ER04-829-000.

On October 12, 2004, Dominion filed a Motion for Continuance before this Commission, requesting a two-week extension of the dates for submitting rebuttal testimony, the dates for submitting pre-hearing briefs, and the evidentiary hearing. By Order dated October 14, 2004, the Commission, despite its readiness to proceed in accordance with the previously established schedule, granted the continuance and suspended the procedural schedule until further notice. The Order was issued subject to Dominion's express acknowledgement that it wished that the requested continuance be granted despite the fact that the hearing could not be reconvened before the end of 2004 and the fact that the Commission had limited available hearing time in the first quarter of 2005.

On October 26, 2004, a hearing was held before the Commission for the limited purpose of receiving testimony from public witnesses. At that hearing, the NC Towns made a statement on the record.

On November 5, 2004, the Commission conducted a status conference at which Dominion and the Public Staff suggested the use of an expedited procedure, including the holding of an oral argument in lieu of an evidentiary hearing and the waiving by all parties of cross-examination of witnesses who filed testimony in the proceeding. On November 8, 2004, the Commission issued an Order setting a new procedural schedule for the filing of pre-hearing briefs and requiring all parties to inform the Commission whether or not they would agree to waive cross-examination of other parties' witnesses.

On November 8, 2004, the Public Staff filed its Pre-Hearing Brief. On November 10, 2004, Dominion filed its Reply to Public Staff's Pre-Hearing Brief. In connection with that reply brief, Dominion and PJM submitted a Joint Offer of Settlement (JOS) to the Commission in an attempt to facilitate the Application approval process by eliminating the need to hold an evidentiary hearing and cross-examination.

On November 10, 2004, in a separate but related proceeding at the Virginia State Corporation Commission (VSCC), the VSCC issued its Order Granting Approval of the Company's Virginia application pursuant to the Virginia Electric Utility Restructuring Act and Title 56 of the Code of Virginia, subject to the terms and conditions of the partial stipulation in that case. The Company had filed an application to integrate its transmission system with PJM as PJM South with the VSCC on June 27, 2003, in Docket No. PUE-2000-00551 (VSCC Application).

On November 18, 2004, the Commission issued an Order declining to adopt the proposed expedited procedure because several parties refused to waive cross-examination of witnesses. On November 24, 2004, the Commission rescheduled the evidentiary hearing for January 19-21, and January 26-27, 2005.

On December 7, 2004, PJM and NCEMPA each filed with the Commission a pre-hearing brief.

Prior to the evidentiary hearing in this proceeding, Dominion was able to reach a settlement agreement with Progress. As a result of the settlement, Progress withdrew its opposition to the Company's Application. On December 21, 2004, Progress withdrew the testimony of its only witness in this proceeding. That Settlement Agreement (Progress Settlement) was filed with the Commission on December 16, 2004.

Also on December 16, 2004, the Company and PJM filed rebuttal testimony and submitted a revised JOS.

On January 7, 2005, NCEMPA filed the affidavit of Donna S. Painter.

By Order issued January 10, 2005, the Commission addressed pre-hearing procedural motions and encouraged the submission of pre-hearing statements of position by parties that did not file testimony in the proceeding. Accordingly, on January 14, 2005, the Attorney General filed with the Commission a pre-hearing statement of position. This was followed on January 18, 2005, by the Public Staff's statement of requested relief.

The Commission convened an evidentiary hearing in this proceeding on January 19, 2005, which continued on January 20, 21, 26 and 27, 2005, for the purpose of receiving testimony from public witnesses and the pre-filed testimony and exhibits of the parties. The Commission allowed the pre-filed direct and rebuttal testimony and exhibits of the Company's witnesses, the pre-filed direct and rebuttal testimony and exhibits of PJM's witnesses, the pre-filed testimony of CIGFUR I's witness, the pre-filed affidavit of NCEMPA's witness, and the pre-filed direct testimony and exhibits of the Public Staff's witnesses to be admitted into evidence, subject to the right of cross-examination.

Proposed orders and briefs were filed by the parties on or about March 7, 2005.

In its cover letters transmitting its proposed order and brief, Dominion requested that the Commission issue an order approving the Application "by no later than March 30, 2005." PJM similarly requested that the Commission issue a decision "by the end of March." Dominion stated that it needed a decision by that date "to allow integration on May 1, 2005, the latest date by which the Company can integrate into PJM with certainty before the summer peak season."

In order to expedite proceedings in this docket, the Commission issued a Notice of Decision on March 30, 2005, conditionally approving the requested transfer. In its Notice of Decision, the Commission stated that a full Order would be issued explaining in greater detail the reasons for the Commission's decision and providing additional explanation for the conditions imposed. The Commission further stated that Dominion and PJM shall notify the Commission in writing not later than April 15, 2005, and before taking any further action to transfer operational control of Dominion's transmission facilities located in the State of North Carolina to PJM, that Dominion and PJM accept and agree to be bound by the conditions imposed by the Commission on its approval of the Company's Application in this proceeding and the statements and assertions concerning the Commission's jurisdiction set forth in the Notice of Decision.

On April 15, 2005, PJM filed a letter "communicat[ing] its acceptance of the conditions directed to PJM in the Notice of Decision." Also on April 15, 2005, the Commission issued an Order allowing Dominion's request for an extension of time to make the filing required in the Notice of Decision until one day after the issuance of the Commission's full Order in this matter.

Based upon Dominion's verified Application, the testimony and exhibits received into evidence at the hearing, and the record as a whole in this docket, the Commission now makes the following

FINDINGS OF FACT

1. Dominion is duly organized as a public utility under the laws of the State of North Carolina subject to the jurisdiction of the Commission.

2. Dominion is a vertically integrated utility engaged in the business of generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina pursuant to an exclusive franchise granted under State law. Dominion provides retail electric service to approximately 104,000 customers in northeastern North Carolina.

3. Dominion provides utility service to retail customers in Virginia and North Carolina on a system-wide basis, with retail customers in Virginia and NC being served by common generation and transmission facilities.

4. Most of the electricity delivered by Dominion to its retail customers in North Carolina is generated at facilities owned or controlled by Dominion, most of which are in

Virginia. Dominion owns or controls approximately 18,700 MW of electric generating capacity and purchases a relatively small amount of electricity in the wholesale electricity market.

5. Dominion utilizes transmission facilities in Virginia and North Carolina and distribution facilities in North Carolina to deliver electricity to its retail customers in North Carolina. Dominion owns and operates approximately 14 miles of 500 kV transmission lines, 477 miles of 230 kV transmission lines, and 485 miles of 115 kV transmission lines in North Carolina.

6. PJM is a limited liability corporation with its principal office in Norristown, Pennsylvania. Originally formed in 1956 as a tight power pool primarily among utilities in Pennsylvania, New Jersey and Maryland, PJM is a FERC-jurisdictional entity approved as an independent system operator (ISO) in 1997 and as a regional transmission organization (RTO) in 2002.

7. Dominion's Application seeks authorization to transfer operational control of its transmission facilities in North Carolina to PJM and to join PJM as PJM South. The Application indicates that Dominion intends to turn all facilities in North Carolina operating at 69 kV or greater and all listed transformers, capacitors, reactors and static VAR compensators over to PJM's operational control for the purpose of providing transmission service under the PJM OATT.

8. Dominion's proposal to integrate with PJM actually encompasses far more than the transfer of operational control over transmission facilities located in North Carolina.

9. North Carolina has elected to retain a traditional electric industry structure and to require utilities to furnish electric service on an integrated, least-cost basis at just and reasonable cost-based rates to their North Carolina retail customers pursuant to a comprehensive regulatory structure.

10. North Carolina has explicitly chosen not to restructure and deregulate electric utility service and still requires the Commission to (a) foster the continued service of public utilities on a well-planned and coordinated basis that is consistent with the protection of the public health and safety and the promotion of the general welfare; (b) promote the inherent advantages of regulated public utilities; (c) provide just and reasonable rates consistent with the long-term management and conservation of energy resources; and (d) encourage and promote harmony between public utilities, their users, and the environment.

11. Allowing Dominion to join PJM as originally proposed in the Application or in accordance with the revised JOS would result in a net economic detriment to Dominion's North Carolina retail ratepayers for at least the first ten years after integration.

12. Dominion's integration into PJM, either as originally proposed or as modified by the revised JOS, would not be justified by the public convenience and necessity.

13. The Regulatory Conditions set forth herein are adequate to ensure that Dominion's North Carolina retail ratepayers are held harmless from any adverse effects resulting from Dominion's integration into PJM.

14. With the adoption of Regulatory Conditions set forth herein, Dominion's integration into PJM is justified by the public convenience and necessity.

15. Dominion's integration into PJM may provide an incremental benefit to the Company's North Carolina retail customers by improving the reliability of the transmission grid.

16. Dominion's integration into PJM may provide an incremental planning benefit to the Company's North Carolina retail customers.

17. Dominion's integration into PJM may provide an incremental benefit to the Company's North Carolina retail customers by improving the Company's access to additional generation resources.

18. A physical "carve out" of Dominion's North Carolina service area is not in the best interests of the Company's North Carolina retail customers.

19. The Commission does not have jurisdiction to consider NCEMPA's claims.

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

These findings of fact are essentially informational, jurisdictional, and procedural in nature and are uncontroverted. They are supported by the Application and the exhibits thereto and the direct and rebuttal testimony presented by the Company, PJM, and the Public Staff in this proceeding.

The Company's Application filed on April 2, 2004 was made pursuant to G.S. 62-111(a) for authority to transfer operational control of its transmission facilities located in North Carolina to PJM. Attachment A to the Company's Application is a map of the Company's transmission facilities within North Carolina. Attachment B to the Application contains a complete list of transmission facilities that are the subject of the Application.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is uncontroverted. It is supported by the Application and the exhibits thereto and the direct and rebuttal testimony presented by the Company, PJM, and the Public Staff in this proceeding.

In 1927, three companies in the Pennsylvania-New Jersey area – Public Service Electric and Gas Company, Potomac Electric Power Company, and Pennsylvania Power and Light Company – formed an electric power pool whereby each could benefit from interconnection of their systems. In 1956, this power pool was expanded to include Atlantic City Electric Company, Delmarva Power and Light Company, Baltimore Gas and Electric Company, and several utilities owned by General Public Utilities, Inc. The PJM power pool was set up to manage the transmission systems and coordinate generation capacity between the constituent members. It was operated by an independent staff referred to as the PJM Office of Interconnection. In 1993, this office was established as the PJM Interconnection Association.

In July 1996, nine of the ten members of the PJM pool filed with the FERC a series of agreements that represented a comprehensive restructuring of the PJM pool into an ISO. The tenth member filed a competing proposal. The FERC rejected both proposals and ordered the utilities either to file a new ISO proposal by December 31, 1996, or to file a joint pool-wide pro forma OATT in compliance with FERC Order No. 888.

In March 1997, the PJM Interconnection Association was converted into a limited liability company and renamed PJM Interconnection, LLC. On June 2, 1997, the members of the PJM pool filed the following with the FERC: an amended and restated Operating Agreement, a Transmission Owners Agreement, a PJM OATT, and a Reliability Assurance Agreement Among Load Serving Entities in PJM (RAA). The Operating Agreement established an independent body to operate the ISO, administer the PJM OATT, operate the pool spot energy market (referred to as the Power Exchange), and approve a regional transmission expansion plan. It also provided for an independent Board of Managers that would be responsible for supervision and oversight of the day-to-day operations of the PJM pool. In late 1997, the FERC issued an order conditionally authorizing the establishment of an ISO and conditionally accepting the OATT and power pool agreements.

On October 11, 2000, the PJM owners and PJM jointly submitted a filing to comply with FERC Order No. 2000 and requested that PJM be approved as an RTO. By Order dated July 12, 2001, the FERC granted PJM provisional RTO status, noting that PJM had operational authority over all the transmission facilities under its control; that, under its OATT and the PJM Operating Agreement, PJM is the sole administrator and transmission provider; and that PJM has clear authority over the dispatch of generation within its control area.

The FERC granted PJM full RTO status in December 2002. The PJM RTO has continued to expand as Allegheny Power, Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Power and Light (DP&L) have joined PJM as PJM West between 2002 and 2004.

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

The evidence supporting these findings of fact is found in the Application and the exhibits thereto and the direct and rebuttal testimony presented by the Company, PJM, and the Public Staff in this proceeding.

Dominion's Application characterizes the relief sought by Dominion as requesting the authority to allow PJM to assume functional control of Dominion's transmission system. However, the evidence demonstrates that Dominion's participation as a member of PJM would entail far more than simply allowing PJM to operate Dominion's transmission system.

For example, as Public Staff witness Morey testified, PJM operates two large regional wholesale power markets – a day-ahead market and a real-time market. According to Dominion witness Morgan, the day-ahead energy market provides PJM members with options for price certainty by allowing them to obtain commitments to energy prices and transmission congestion charges on a day-ahead basis. The real-time energy market handles deviations between day-ahead expectations and real-time results. The sale of wholesale power and the order of dispatch of generating units within these wholesale markets are controlled by PJM. Witness Morgan testified that Dominion will participate in PJM's wholesale power markets.

Public Staff witness Floyd's testimony raised the issue of dispatch control and direction as a result of Dominion's participation in PJM and its power markets. Witness Floyd testified at length about the similarities between PJM's dispatch and Dominion's dispatch protocols, explaining that both utilize security-constrained economic dispatch by reviewing the operating status of the generation fleet, ranking those units in economic order, and dispatching the lowest cost, constant run units first. Other than the parameters of market prices versus actual costs being used to make dispatch decisions, there is no difference between what Dominion is currently doing and what PJM will do upon integration. Similarly, Dominion witness Morgan explained in his testimony that PJM dispatches the generation fleet within its control area for the same purposes that Dominion dispatches its generation fleet, although PJM uses market price signals (bids) rather than actual costs to accomplish its dispatch and does it on a region-wide basis regardless of ownership. Witness Floyd expressed concern, however, about the change from dispatch decisions being made by Dominion to those decisions being made by PJM with Dominion simply executing those decisions.

Secondly, Dominion, as an LSE, transmission owner, market participant, and member of PJM, would assume responsibilities and obligations under PJM's various agreements. PJM's Operating Agreement is the primary document governing the operations of PJM and its relationship to Dominion. It provides for the governance and organizational structure of PJM and establishes the procedures by which PJM conducts its business. PJM's Operating Agreement has been amended numerous times since it was filed with Dominion's Application on April 2, 2004. The most recent version is posted on PJM's website. The PJM South Transmission Owners Agreement (PJM South TOA) is the primary document that would be used to facilitate the integration of Dominion into PJM. It has been amended since Dominion's application was filed with the Commission on April 2, 2004. The PJM South Reliability Assurance Agreement (PJM South RAA) is the primary document that facilitates the relationship between PJM and each LSE within the PJM South control area that is a party to the agreement. Lastly, the PJM OATT applies to all transmission facilities turned over to PJM's operational control, and PJM provides transmission service over those transmission facilities pursuant to its OATT. Upon Joining PJM, Dominion would cease to be a NERC-certified control area and PJM would become Dominion's Reliability Coordinator. All control area requirements and obligations imposed by the relevant NERC policies would become the responsibility of PJM.

Thus, Dominion's proposal to integrate with PJM actually encompasses far more than the transfer of control over transmission facilities located in North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-10

These findings of fact are essentially informational in nature and are uncontroverted. The Commission takes judicial notice of the North Carolina Public Utilities Act, Chapter 62 of the North Carolina General Statutes, and the state of the law in North Carolina as it relates to electric industry restructuring.

In April 1997, the North Carolina General Assembly established the Study Commission on the Future of Electric Service in North Carolina (Study Commission). The members of the

Study Commission include legislators and representatives from the various electric suppliers; residential, industrial and commercial consumers; the environmental community; and a power marketer. The Study Commission met a number of times through 2002 to examine the current cost and adequacy of electric service in North Carolina and to explore the complex issues that would be involved in retail competition, including, among others, reliability, fairness among customer classes, universal service, reciprocity, stranded costs, the impact on the environment, and tax implications. The Study Commission adopted recommendations in April 2000 that would have transitioned the State to fully competitive retail electric service, but no implementing legislation was ever introduced. The Study Commission has suspended any effort to implement retail competition in North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

The evidence supporting these findings of fact is found in the Application and the exhibits thereto, the revised JOS, and the direct and rebuttal testimony presented by the Company, PJM, and the Public Staff in this proceeding.

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.

See, e.g., Order Approving Application, Docket No. E-2, Sub 753 (2000) (Commission approval of Carolina Power & Light Company's application to transfer ownership to a holding company).

On December 16, 2004, Dominion and PJM filed a revised JOS proposing several conditions to which they would agree to be bound if the Commission approves Dominion's application. In addition to some informational reporting obligations, Dominion proposed to exclude certain costs and revenues from North Carolina rates for up to ten years. In summary, Dominion proposed not to include in base rates prior to March 31, 2006, any increase in transmission costs to the Company or any revenues resulting from FERC orders imposing Seam Elimination Cost Adjustments (SECAs). Dominion proposed not to include in base rates prior to December 31, 2014, a number of additional categories of costs arising from its integration with PJM, including: (a) PJM administrative fees or any replacement mechanism for such fees approved by the FERC; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs), auction revenue rights (ARRs), or any replacement mechanism for such cost and revenues approved by the FERC; or (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure used for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service. In clarification of the foregoing, Dominion's commitment in Paragraph 1(c) of the revised JOS did not include a commitment to exclude from base rates: (i) any increase in transmission charges resulting from an increase in the Company's annual transmission revenue requirement; or (ii) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone and which are not included in the Company's transmission revenue requirement. With regard to the fuel factor, Dominion proposed to credit a portion of its FTR revenues to the cost of PJM Purchases (purchases from the PJM market in excess of the output of the Company's resources) through December 31, 2014. In addition to these rate protections proposed by Dominion, PJM proposed certain curtailment protocols applicable to Dominion's retail customers and agreed to initiate a stakeholder process to consider revisions to applicable procedures in order to publicly post, for a sixty (60) day period prior to implementation, requests by load serving entities seeking to change from a single load aggregation zone for the establishment of locational marginal pricing (LMP) and settlement for its load.

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.

Quantifiable Costs Exceed Quantifiable Benefits

A primary concern raised by Dominion's application is the cost to be paid by North Carolina retail consumers as a result of Dominion's membership in PJM. The cost/benefit study prepared by Charles River Associates (CRA) and submitted by Dominion with its Application facially demonstrates that the net present value of the quantifiable costs from 2005 through 2014 would outweigh the quantifiable benefits by at least $1.8 million for its North Carolina customers. Under the study's benchmark case, the total net quantifiable benefits of $8.4 million are offset by the net quantifiable costs of the PJM administrative charges of $10.2 million. Witness Stoddard agreed that the benchmark study shows a net cost to customers of $1.8 million on a net present value basis. Thus, during the years 2005 through 2014, Dominion's North Carolina retail customers would pay at least an additional $1.8 million for their electric service on a net present value, without receiving any corresponding quantifiable benefits.

The analyses conducted by CRA at the request of the Public Staff and Public Staff witness Morey indicate a much wider range for the possible costs to North Carolina retail customers resulting from Dominion joining PJM. The Public Staff's witnesses presented compelling evidence that the quantifiable net costs will be considerably larger than the $1.8 million projected by CRA – approximately $4.1 million to $10.1 million. Public Staff witness Morey testified that the accuracy of the cost/benefit study is compromised by its procedures and assumptions. Specifically, it is compromised by its incorrect characterization of the Base Case, by its choices of hurdle rates, by the extremely limited benchmarking of the GE MAPS model, and by its failure to recognize certain material financial risks that will attend Dominion's PJM membership. Each of these elements of the study reduces the reliability of the study's results. For example, the study assumed that Dominion, AEP, ComEd, and DP&L were PJM members in the Change Case while erroneously positing that none were members in the Base Case. Consequently, all of the analyses conducted by CRA under these definitions of the Base Case and the Change Case are incorrectly defined. All of the analyses estimate net benefits associated with the simultaneous decision of all four utilities to become PJM members, and do not isolate the net benefits of only Dominion becoming a PJM member. When an analysis is conducted with the correct definition of the Base Case, that is, with only Dominion out of PJM, the net cost to NC retail customers is shown to be $4.1 million.

Furthermore, the cost/benefit study indicates that the net quantifiable loss for North Carolina retail customers could be as high as $2.2 million under the case in which the Bedington-Black Oak transmission interface was upgraded and as high as $4.7 million under a high load growth scenario. Dominion witness Stoddard agreed that considering these two scenarios together could produce higher net costs than either one of these scenarios would produce when considered alone.

In addition, the CRA study shows that North Carolina's retail consumers would pay increased fuel costs if Dominion joins PJM. During the 2005-2014 period covered by the study, the increase in fuel costs is estimated to be $2.8 million. This increase in fuel costs would result from Dominion's increased use of purchased power to serve its retail customers. Dominion witness Evans testified that the Company's participation in PJM is expected to increase the instances in which purchased power will be available at a lower cost than that at which Dominion can generate power itself. Thus, although the fuel component of the purchased power may be higher than that of Dominion's self-generated power that it will replace, the reductions in operating and maintenance expenses at Dominion's generating plants could result in lower overall costs. On the surface, Dominion's actions of buying power cheaper than it can generate power would appear to benefit consumers. However, such would not be the case in the near future. This is because consumers would not realize the above-noted CRA study projected savings of $12.7 million and $2.3 million in Dominion's operating costs that are already included in their base rates until there is a general rate case, an event that may not occur until at least April 2010 when the Rate Change Moratorium Period established in the Commission's March 18, 2005, decision in Docket No. E-22, Sub 412 expires. On the other hand, consumers would pay the increased fuel costs every year because they would be passed through the annual fuel cost rider. Thus, it is highly likely that consumers would pay higher fuel costs from 2005 through 2010, but would not receive a corresponding decrease in base rates during that period.

The evidence shows that Dominion's membership in PJM, absent further regulatory conditions, would result in a net increase in quantifiable costs for North Carolina ratepayers from 2005 through 2014. Those increased costs could range from $4.6 million (adding the CRA study's general cost increase of $1.8 million to the increased fuel costs of $2.8 million) to $12.9 million (adding the general cost upper range estimate of Public Staff witness Morey, $10.1 million, to the increased fuel costs of $2.8 million). At a minimum, the Commission agrees with the Public Staff that Dominion has incorrectly defined the base case, making the negative net present value of Dominion's integration into PJM at least $4.1 million. In contrast, as a part of Dominion's VSCC Application, it submitted a cost/benefit study for the period 2005 through 2014 in which CRA found that Dominion's membership in PJM would result in net quantifiable benefits of $557.2 million for all customers in Dominion's service area, including both Dominion's Virginia and North Carolina customers. Thus, comparing the quantifiable cost/benefit figures from both of the CRA studies, the net benefits to Dominion customers in its entire service area from 2005 through 2014 would be $557.2 million, while the net costs to Dominion's retail customers in North Carolina would be $1.8 million. Thus, according to all but one of the scenarios considered in the cost/benefit study and by the additional scenarios requested by the Public Staff, the quantifiable benefits to North Carolina ratepayers over the study period of Dominion joining PJM are outweighed by the quantifiable costs of PJM membership.

Potential Loss of Commission Regulatory Authority

As expressed in the public policy statement of G.S. 62-2, the General Assembly continues to believe that the most reliable and efficient means to provide electric service to retail consumers is by fully integrated public utilities operating under regulated rates and providing regulated service. To that end, Chapter 62 grants the Commission extensive authority to set rates, monitor service quality, approve generation and transmission additions, and adjust fuel costs. See G.S. 62-100, 62-110, 62-133 and 62-133.2. An important part of North Carolina's retail rate structure is that public utility rates, composed of the costs of generation, transmission and distribution, are fully bundled into one rate.

PJM is an RTO approved and regulated by the FERC. The FERC has authority under the FPA to set PJM's transmission rates for unbundled wholesale transmission service and to set rates for wholesale sales of energy made through PJM's wholesale power market. Although the line that divides the Commission's and the FERC's regulatory authority between retail transmission and energy rates, as compared to wholesale transmission and energy rates, is fairly clear today, that line could be substantially blurred by Dominion's membership in PJM. For example, Dominion's witnesses testified that Dominion intends to fully participate in PJM's wholesale power market. Dominion will bid all of its generation into the market and buy back what it needs to serve its customers from that market. Sales in the PJM market are made at FERC-approved market based rates. Each day's price for all sellers and buyers is set by the highest bid accepted by PJM. This market-clearing price could be construed as Dominion's "cost" for retail ratemaking purposes. Thus, Dominion's cost of producing electricity to serve North Carolina consumers might no longer be based on Dominion's actual costs, but rather on PJM's market-based rates.

At present, Dominion provides one retail "product" to its North Carolina retail customers consisting of three elements that are bundled together – energy, transmission and distribution. However, when Dominion bids its generation into the PJM market, that transaction could be deemed an unbundling of its retail service. That is, Dominion might be separating the energy element from the transmission and distribution elements. Further, when Dominion buys the electricity to serve North Carolina's retail consumers back from PJM, it will purchase that electricity at PJM's market clearing price, which is a FERC-approved rate. That transaction could be deemed to be a wholesale sale under the FPA. Thus, it is possible, under the filed rate doctrine, that the FERC-approved rate governing that transaction would become Dominion's cost basis for purposes of retail service to its North Carolina customers.

In Nantahala Power & Light v. Thornburg, 476 U.S. 953, 106 S. Ct. 2349, 90 L. Ed. 2d 943 (1986) (Nantahala), the Commission attempted to allocate a higher percentage of hydroelectric power to Nantahala for the purpose of setting Nantahala's retail rates than that set by the FERC in approving wholesale sales to Nantahala. The Supreme Court held that the FPA required the Commission to use the FERC-mandated allocation percentage when setting Nantahala's retail rates. The Court based its decision on the filed rate doctrine, emphasizing that a utility is entitled to rely upon wholesale rates that have been filed with and approved by FERC. Further, the Court reasoned that if Nantahala was required to accept the lower retail rates set by the Commission, then it would be harmed by its inability to recover the "trapped" difference between the FERC-approved and Commission-approved rates.

In Pacific Gas & Electric Co. v. Lynch, 216 F. Supp. 2d 1016 (N.D. Cal. 2002). (Pacific Gas & Electric), PG&E sued the California Public Utilities Commission (CPUC) for recovery of alleged under-collections resulting from the runaway wholesale prices in California's wholesale markets in 2000-2001 following the start of retail choice. PG&E asserted that its massive deficits, allegedly amounting to $8.3 billion, were caused by the CPUC's refusal to remove a retail rate freeze and allow the company to pass through the increased wholesale prices. In ruling upon whether the CPUC was required by the filed rate doctrine to allow PG&E to pass through the wholesale prices that PG&E paid for purchases of electricity from the California Power Exchange, the court held:

> [t]he filed rate doctrine applies here in much the same way as it does under a cost-of-service regime. The rule adopted by the court may be stated as follows: costs of wholesale energy, incurred pursuant to rate tariffs filed with FERC, whether these rates are market-based or cost-based, must be recognized as recoverable costs by state regulators and may not be trapped by excessively low retail rates or other limitations imposed at the state level.
>
> In light of this rule, the novel features of California's regulatory scheme are in some ways ultimately irrelevant. Utilities must be able to recover their wholesale costs incurred pursuant to FERC-filed tariffs, even when FERC allows sales of wholesale electricity at prices the market will bear, even when this federal approval is based in part on a retail rate freeze and even when, as here, FERC subsequently has determined that the market-based rates were, at times, unreasonable.

Pacific Gas & Electric, 216 F. Supp.2d, at 1038.

The prices paid for wholesale purchases from PJM are not necessarily cost-based, but instead are established by market forces. In fact, there is no requirement that suppliers who sell electricity in PJM's market offer that electricity at their marginal cost of production. Thus, the Commission's authority to set cost-based energy rates for Dominion's North Carolina retail customers could be preempted by higher PJM market-based rates approved by the FERC.

The same unbundling effect found in Pacific Gas & Electric could occur when Dominion transfers the operation of its transmission system to PJM. That is, Dominion could be deemed to be separating the transmission element from the energy and distribution elements of its currently bundled product. Further, the same Nantahala preemption and pass-through of "trapped" transmission charges could occur with Dominion's transmission costs, which the record indicates are lower than those found anywhere else in PJM. In essence, PJM will become the provider of transmission service to Dominion, and Dominion will buy that transmission service from PJM at FERC-approved rates. That transaction could be deemed a sale of unbundled transmission service under the FPA. Thus, it is possible that, under the filed rate doctrine, PJM's FERC approved rates governing that transaction would become Dominion's cost basis for purposes of setting retail rates for Dominion's North Carolina consumers. Indeed, in the GridSouth RTO order, the FERC conditioned its approval on Duke and Progress Energy taking all transmission services, unbundled wholesale and bundled retail transmission, under the GridSouth tariff. Order Provisionally Granting RTO Status, 94 FERC ¶ 61,273 (March 14, 2001). Under a similar approach, Dominion's lower transmission rates for service to its North Carolina retail customers could be preempted by the higher PJM rates set by the FERC. Similarly, the actual generation costs incurred by Dominion in providing electric service to its North Carolina retail customers could be preempted by the uncertain market-based rates approved for PJM by the FERC.

Absent further regulatory conditions, Dominion's membership in PJM could result in the Commission's loss of state law regulatory authority over Dominion's generation and transmission services, as well as the rates paid by North Carolina consumers for those services.

Failure of JOS to Offer Adequate Protection

The conditions proposed by Dominion and PJM in their December 16, 2004, 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 Paragraph 10 of the JOS, Dominion agrees to "promptly respond to concerns raised by the NCUC concerning reliability or quality of service to the Company's retail customers in North Carolina." However, this condition adds nothing, since G.S. 62-42 already provides the Commission with the authority to compel Dominion to correct any deficiencies in the services provided to its retail customers, as Dominion acknowledged during the hearing. Similarly, Paragraph 11 states that Commission approval of the revised JOS would not alter North Carolina law concerning the provision of retail electric service to customers through bundled retail service. Again, this condition adds little in the way of protecting the Commission's authority. Rather, it is merely a restatement of existing North Carolina law under G.S. 62-110 and 62-133, which establish that Dominion's services and rates are structured as fully integrated, bundled services.

Dominion's and PJM's revised JOS provides no assurances, however, as to what Dominion and PJM will do if the Commission's authority is challenged under the filed rate doctrine. For instance, there is no stipulation that Dominion will hold North Carolina consumers harmless from the effects of federal preemption under the filed rate doctrine, or that Dominion will agree not to argue that the Commission's authority is preempted. Indeed, Dominion's testimony is that any waiver of the effects of the filed rate doctrine is limited to the period ending on December 31, 2014, the same as the period in which North Carolina consumers would be held harmless from some costs. Thus, the proposed conditions fail to effectively address the potential loss of the Commission's regulatory authority over Dominion's rates and services.

The 2005 through 2014 period for application of proposed conditions under the revised JOS coincides with the period covered by the CRA cost/benefit study. In response to questions about why the CRA Study did not address a longer period of time, Mr. Stoddard testified that the assumed facts and variables in such a study become more uncertain the farther out those assumptions are made. There is little argument that such increased uncertainties were a reasonable basis for Dominion's decision to limit the CRA study to ten years. The Public Staff's witness agreed with Mr. Stoddard's view on this point. Indeed, the Commission, in its IRP process, uses a ten-year planning horizon. However, Dominion's proposal to end the conditions that would offer some level of protection to retail customers after ten years is not reasonable. In effect, Dominion proposes that the uncertainties and risks that prohibit it from making cost/benefit projections beyond 2014 be shifted from Dominion to its retail customers on January 1, 2015. Thus, Dominion's proposal places the bulk of the risks and uncertainties on its retail customers. As such, absent additional regulatory conditions, the revised JOS does not adequately cure the deficiencies in Dominion's Application that result in the application's failure to meet the public convenience and necessity standard.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

The evidence supporting these findings of fact is found in the Application and the exhibits thereto, the revised JOS and Progress Settlement, and the direct and rebuttal testimony presented by the Company, PJM, and the Public Staff in this proceeding.

Despite the evidence presented against approval of the proposed transfer, all parties have recommended Commission approval coupled with the adoption of appropriate additional regulatory conditions. However, various parties recommended different conditions and there was no agreement on a common set of conditions. After carefully considering the potential benefits, costs, risks, and harms, the Commission concludes that certain Regulatory Conditions may be adopted in addition to those proposed by Dominion and PJM in the revised JOS and the Progress Settlement that will adequately protect North Carolina retail ratepayers and provide commensurate benefits to those consumers. The risks of Dominion's membership in PJM should be borne by Dominion, not Dominion's North Carolina customers. In order to properly place those risks on Dominion, the Commission adopts specific Regulatory Conditions that will result in Dominion's North Carolina customers being held harmless from the effects of Dominion's membership in PJM.

The additional Regulatory Conditions adopted herein are intended to prevent the proposed transfer from having any known adverse impact on the rates and service of Dominion's North Carolina retail ratepayers; to protect those ratepayers as much as possible from potential harm; and to provide sufficient benefits from the transfer to offset any potential costs, risks, and harms. 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. These Regulatory Conditions, being necessary to justify the public convenience and necessity, shall remain in effect for a period of not less than ten years from the date of Dominion's integration into PJM and shall continue thereafter indefinitely and until further Order of the Commission. The Commission recognizes that these Regulatory Conditions cannot protect Dominion's North Carolina retail customers from all potential risks and harms from the proposed integration, such as the loss of native load priority and physical rights to transmission, but the potential remaining risks and harms are offset by the potential non-quantifiable benefits discussed in more detail below.

Thus, based upon an application of the statutory standard to the facts of this case, with particular attention paid to the additional regulatory conditions imposed herein, the Commission concludes that the proposed transaction is justified by the public convenience and necessity and should be approved.

Ratepayers to Be Held Harmless

Public Staff witnesses Morey, Rosenberg, McLawhorn, Peedin, and Maness testified at length about the real and potential costs that Dominion would incur upon joining PJM and would likely seek to recover from its ratepayers. While some of these costs, such as administrative fees, may be estimated fairly easily, other costs, such as congestion costs, are subject to considerable uncertainty. Nevertheless, Dominion's own cost/benefit study acknowledged that the quantifiable costs of integration outweighed the quantifiable benefits. Moreover, the magnitude of these costs and the accuracy of the study's results were called into question by Dr. Morey.

Public Staff witnesses Floyd, Lam, and Maness further questioned the value of the purported non-quantifiable benefits. These witnesses testified that the known and potential costs outweighed the potential benefits even considering these non-quantifiable benefits. Witness Maness testified that it would not be appropriate for the Commission to approve Dominion's application to join PJM without implementing substantial and virtually indisputable protections for Dominion's North Carolina retail ratepayers. These protections would have to extend over the entire scope of Dominion's service to North Carolina retail ratepayers, including its operations, reliability of service, overall service adequacy, and rates.

The Commission recognizes that integration into PJM would introduce certain new elements to Dominion's cost of doing business in North Carolina, such as PJM administrative fees, congestion charges and congestion credits. As the Company explained, each of these new cost elements is a function of the structure of PJM and is associated with a charge under the PJM Open Access Transmission Tariff or the PJM Operating Agreement.

As noted above, the Commission concludes that the Application cannot be approved without additional regulatory conditions that will protect Dominion's North Carolina retail ratepayers from the known and potential costs which exceed the quantifiable benefits received. The Commission, therefore, will impose the following conditions upon its approval of the requested transfer:

(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:

a. As stated in the testimony of Dominion witnesses, Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administered by PJM; that is, under no circumstance(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

b. Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales;

c. Dominion shall take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; minimization of power outages, efficient restoration of service; and responsive customer service;

d. Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by the FERC; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6, et al. imposing the Seam Elimination Cost Adjustments (SECAs); and

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 1(a) captures the commitments made by Dominion's witnesses at the hearing that the Company's integration into PJM will not cause any change in North Carolina retail ratemaking for the Company's North Carolina retail customers. Specifically, Dominion witness

Koogler testified that the rates for the Company's North Carolina retail ratepayers would continue to be established and calculated in the same way as before Dominion's integration with PJM. As he explained in reference to Koogler Exhibit 1, the formula for establishing rates for retail customers following integration into PJM stays the same. There is no change in the way the formula is set, as the physical assets and the return on rate base will be the same. Regarding fuel and non-fuel costs, the Company will continue to look to actual costs and will not consider what is charged or billed by PJM. In the case of the non-fuel O&M example, as Mr. Koogler detailed, the Company will go back to the actual operating costs of the Company units as it always has.

Dominion's witnesses further testified that once the Company is integrated into PJM, it is likely that all of the Company's retail load will be bid into the energy market. Although the opportunity exists to self-schedule, all of the Company's generation that is available will likely be bid into the energy markets. Dominion's witnesses committed, however that this will not change the North Carolina retail ratemaking process with respect to the Company's North Carolina retail customers. In particular, (i) base rates relating to the Company's owned generation will continue to be set based on the elements included in the Company's cost-of-service for such owned generation and will not be set based upon the market price received for any generation bid or self-scheduled into the market; and (ii) fuel rates will continue to be set pursuant to the fuel methodology set forth in North Carolina G.S. 62-133.2.

To be clear, under Condition 1(a), not only would the same rate-making methodology continue to be used to establish retail rates, but the inputs to the calculation would also be determined in the same manner as they were before Dominion's integration with PJM. For example, Dominion's "costs" for purposes of establishing North Carolina retail rates (including adjustments for changes in the cost of fuel) shall be based upon the Company's actual costs to generate electricity delivered to the grid and not upon the price paid to PJM to purchase such electricity from the market. In addition, Dominion's "costs" for transmission as part of the bundled electric service provided to North Carolina retail ratepayers shall be based upon the embedded costs of the Company's facilities and cost of operation and not upon the price paid to PJM under the PJM OATT. Finally, to the extent that Dominion's rates would be lower if set using the cost of self-supplied ancillary services, they will be set in that manner under this Order. The use of this methodology to determine rates, as has historically been used in North Carolina, is consistent with the commitments made in testimony by the Company's witnesses. As shown in Koogler Exhibits 1 through 6, and as explained by Company witness Koogler, the costs of the generation (and transmission) plant used to serve the Company's retail load will continue to be based on the same cost elements included in the Company's retail cost-of-service reviewed by the Commission in prior rate cases.

Condition 1(b) specifically restates Regulatory Condition 28 from the Commission's October 18, 1999, Order in Docket No. E-22, Sub 380 approving Dominion's merger with Consolidated Natural Gas Company. This condition was offered by the parties as part of a stipulation filed in that proceeding. Although in the instant case the Commission has required Dominion to reaffirm its commitment to all previously imposed Regulatory Conditions, the Commission concludes that particular attention should be drawn to this Condition in the context of the future determination of retail rates. Dominion has argued that a benefit of its integration into PJM is its greater access to lower cost power. Dominion's obligation to its North Carolina retail ratepayers remains to provide bundled electric service utilizing the lowest cost combination of self-generated and purchased power.

Dominion's witnesses Evans and Morgan explained that the Company seeks to purchase power from the market whenever doing so is less expensive than running the Company's own generation assets. 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. Historically over 60 percent of the Company's wholesale purchases either come from PJM or come across the Company's interface with AEP (and thus today would come from PJM). 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 once the Company integrates into PJM would be treated in exactly the same way as they are today. 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. Furthermore, the Commission reserves the right under these Conditions to examine Dominion's bidding strategies and make appropriate adjustments to ensure that Dominion's North Carolina retail ratepayers are not deprived of access to lower-cost power from Dominion-owned generating units or units Dominion controls.

Condition 1(c) protects Dominion's North Carolina retail ratepayers from adverse impacts to reliability as a result of the Company's integration into PJM. Considerable testimony highlighted Dominion's current superior level of reliable electric service to its North Carolina customers. Condition 1(c) requires Dominion to take all reasonable and prudent actions necessary to continue to provide such reliable service to its North Carolina retail ratepayers. Dominion shall not allow its integration into PJM to interfere with its obligations to ensure that (1) sufficient generation is available to meet the demand of its North Carolina retail load and (2) that sufficient transmission capacity is available to fully deliver the power to meet that load.

As stated in the testimony of Dominion's and PJM's witnesses, in the revised JOS, and in their briefs filed in this proceeding, the Commission's approval of the Company's Application subject to the Regulatory Conditions adopted herein and Dominion's participation in PJM will not alter the Commission's authority, jurisdiction, or role in ensuring reliable, cost-effective electric service to Dominion's North Carolina retail customers. Dominion's integration into PJM will not change the control over the Company's generation, and there will be no change in the Commission's authority over generation or transmission planning, certification, or siting authority. North Carolina will retain the jurisdiction that it currently has over generation, including integrated resource planning, resource adequacy, and certification. North Carolina will also retain its jurisdiction concerning matters of transmission planning and siting. In addition, the Commission specifically retains full authority to determine and set rate and non-rate terms and conditions of service; to hear and resolve complaints against the Company; to compel efficient service, extensions of services and facilities, additions and improvements; and to enforce compliance with its rules and regulations and North Carolina law using all available remedies, including the assessment of penalties.

The evidence shows that operation of the Company's generation plants in PJM to serve retail customers should not be altered by membership in PJM and that membership may add the benefit of access to a much broader range of generating units. As Company witnesses Morgan and Thompson explained, except in emergency situations, the Company retains decision-making authority over how its assets are bid into PJM and how the Company satisfies its obligations to serve its native load. Such decisions will be subject to Commission review under North Carolina law pursuant to the Regulatory Conditions adopted herein. In emergency situations, PJM will have the same control over generation that the Company's SOC does today to protect the reliability of service.

Furthermore, G.S. 62-42 authorizes the Commission to require the Company to provide adequate and reliable service to its retail ratepayers in the state, and that authority will not change following integration. Under G.S. 62-42, the Company will still have an obligation to ensure the provision of adequate and reliable service and the Commission will have remedies to address service quality issues. As such, North Carolina will retain its traditional role in ensuring reliable service to its retail customers.

Condition 1(d) restates with minor changes the provisions in the revised JOS filed by Dominion and PJM with respect to the recovery of PJM-related costs from Dominion's North Carolina retail ratepayers through base rates. Because of the uncertainty whether the quantifiable benefits to North Carolina customers of Dominion's integration into PJM will ever exceed the quantifiable costs, the Commission concludes that the PJM-related costs proposed to be excluded from base rates for up to ten years should be excluded indefinitely. The Commission may allow the inclusion of such costs to the extent that quantifiable benefits in a general rate case filed after the initial ten-year period proposed in the revised JOS exceed related costs. The Commission further concludes that "any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement" are also PJM-related costs which should not be included in base rates to be recovered from North Carolina retail ratepayers absent a showing of offsetting quantifiable benefits.

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.

Commission's Jurisdiction Preserved

As discussed previously, approval of the proposed transfer without the imposition of additional regulatory conditions might have jeopardized the Commission's extensive authority over Dominion pursuant to the comprehensive State regulatory scheme established in Chapter 62 to, among other things, set rates, monitor service quality, approve generation and transmission additions, and adjust fuel costs. The Commission, therefore, concludes that it is reasonable to adopt the following Regulatory Conditions intended to protect the Commission's jurisdiction to the extent possible from federal preemption as a result of Dominion's integration with PJM:

(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:

f. Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption.

(4) That Dominion shall continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission.

Condition 1(f) is similar to regulatory conditions adopted in other proceedings under G.S. 62-111, including Condition 31 adopted in Docket No. E-22, Sub 380. This Regulatory Condition is intended to forestall any argument that the Commission, in setting Dominion's retail rates or otherwise acting pursuant to its State law authority, is violating the filed rate doctrine or is otherwise preempted in its action by the FPA or other federal law. By proposing to exclude certain PJM-related costs from rates for a given period of time, Dominion has already acknowledged in the revised JOS and in its testimony that it has the right and the ability to waive federal preemption arguments and the effects of the filed rate doctrine. By accepting the Commission's approval of the transfer subject to the Regulatory Conditions adopted herein, Dominion may not subsequently argue, for example, that the Commission, in setting bundled retail rates pursuant to Regulatory Condition 1(a), is improperly trapping costs or unlawfully failing to flow through to retail ratepayers costs approved by the FERC. In addition, if, for example, the FERC were to approve transmission costs above Dominion's transmission cost of service as determined by the Commission, the effect of this hold harmless Condition would be that Dominion would not be allowed to recover that difference from its North Carolina retail ratepayers.

Condition 4 does not impose any new substantive requirements, but provides that in adopting the Regulatory Conditions set forth herein Dominion is obligated to continue to comply with all previously approved Regulatory Conditions and Codes of Conduct.

Extension of Proposed Settlements

In filing the revised JOS, Dominion and PJM proposed several conditions to which they would agree to be bound if the Commission approves Dominion's application. As discussed above, the Commission has concluded that modifications are required to a few of these proposed conditions for the transfer to be justified by the public convenience and necessity. These modified provisions are made explicit Regulatory Conditions to the Commission's approval. In addition, these Regulatory Conditions shall remain in effect for a period of not less than ten years from the date of Dominion's integration into PJM and shall continue thereafter indefinitely and until further Order of the Commission. The Commission further concludes that Dominion and PJM shall comply with the remaining provisions set forth in the revised JOS to the extent not altered by the additional Regulatory Conditions adopted herein. It is important, for example, that the Commission and interested North Carolina stakeholders have the information necessary to evaluate the impact of Dominion's integration.

Also in the course of this proceeding Dominion and PJM reached a settlement with Progress which was filed on December 16, 2004. In this agreement, Dominion and PJM committed to continue to perform Dominion's obligations under various operating and reliability agreements, including unwritten practices, procedures, and courses of conduct; to continue to cooperate with Progress in the operation of Dominion's transmission system and generating resources; and to continue their good faith efforts to negotiate and conclude a Joint Operating Agreement (JOA) to address loop flows, VARS, and other operational matters, if any, that materially impact Progress's system, arising from Dominion joining PJM. Dominion and PJM further committed that interregional planning and coordination understandings will continue, that Dominion shall continue to participate on existing Interregional Planning Committees, such as VST (Virginia-Carolinas Subregion (VACAR) of the Southeastern Electric Reliability Council, Southern Company, and Tennessee Valley Authority (TVA)), VAST (VACAR, AEP, Southern Company, and TVA), and VEM (VACAR, East Central Area Reliability Coordination Agreement (ECAR), and Mid-Atlantic Area Council (MAAC)), with PJM representation as needed, and that coordination of transmission maintenance schedules will continue, with Dominion Virginia Power working with the VACAR groups.

Duke argues that the Commission, in approving Dominion's Application, should attach certain conditions similar to those in the Progress Settlement. Duke states that unlike Progress, it is not directly interconnected with the Dominion transmission system. Duke is, however, directly interconnected with the AEP control area now under the control of PJM, a member with Dominion and Progress of VACAR, and a party to the various regional operating agreements referenced in the Progress Settlement. Duke notes that the operating characteristics of any one of the VACAR systems can have operational impacts on neighboring VACAR systems which encompass most of the retail customers in North Carolina. These characteristics include parallel flows, voltages and the availability of reserves. To the extent issues may arise in these arenas as the result of – or even incidental to – PJM assuming control of the Dominion system (as well as the AEP control areas), Duke believes they can be resolved by good faith discussions among the parties under the umbrella of the various VACAR and other regional agreements. Duke anticipates continuing to working with Dominion and PJM with regard to such matters, but requests the Commission to make clear that PJM should discharge Dominion's obligations pursuant to these agreements with regard to all parties as Dominion would have been so obligated to do in the past. The fact that PJM will assume control of Dominion's transmission system should not diminish any protections for North Carolina utilities or their customers which are present in these agreements. Duke believes that the Commission should condition approval of Dominion's Application on Dominion and PJM adhering to the commitments, procedures and processes in the Progress Settlement. Duke identified certain provisions of the Progress Settlement that it believes should have more general applicability, noting that this should not work any hardship on Dominion or PJM since they have already agreed to them.

The Commission agrees with Duke and shall explicitly condition its approval of the proposed transfer on compliance with the terms of the Progress Settlement. The Commission will require Dominion and PJM to, with regard to all of the signatories thereof, honor, and discharge

Dominion's obligations pursuant to, the various VACAR and other regional agreements referenced in the Settlement Agreement, including, but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have been customarily observed by the participants but do not necessarily exist in written form.

Finally, the Commission finds that the facts and circumstances in this matter are unique, that this case is a very close one, that any application of this nature must be independently reviewed and evaluated with respect to the specific evidence presented in that case, and that this decision shall not serve as precedent with respect to any future request by a utility to join an RTO or otherwise transfer operational control over its transmission facilities.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is found in the Application and the exhibits thereto and the direct and rebuttal testimony presented by the Company, PJM, and the Public Staff in this proceeding.

The evidence in this proceeding demonstrates that PJM provides some level of incremental non-quantifiable benefit to the Company's North Carolina retail customers by enhancing the reliability of the transmission grid that serves those customers. Company witness Thompson, Director of the Company's System Operations Center (SOC), testified that PJM membership will provide benefits to Dominion's North Carolina retail customers as follows:

- PJM will be able to view the entire PJM footprint and coordinate the delivery of better information to transmission system owners in real time.
- Dominion will have access to a larger pool of generation resources to call upon in an emergency and will be able to help prevent an emergency, such as a situation in which PJM implements a Maximum Emergency Generation action to order all generators to their maximum output.
- Significant improvements will be realized in the calculation of Available Transfer Capability (ATC) due to the internalization of three out of four of the existing seams and the use of a flow-based methodology.
- PJM will be able to respond faster to alleviate transmission problems through the use of LMP to manage congestion within the entire PJM footprint instead of using the NERC TLR procedure.
- The contingency analysis will be improved by both PJM and Dominion performing the analysis in real time.
- PJM's region-wide security-constrained dispatch operation will identify problems in regional flows that Dominion alone could not have foreseen due to the lack of regional information and the lack of control of generation dispatch.
- Potential reliability problems will be avoided by utilizing PJM's methodology for analyzing and prioritizing, if necessary, simultaneous transmission outage requests by two transmission owners within the PJM footprint.

The evidence establishes that integration into PJM will allow the Company to better address problems and challenges that are inherent in the interconnected nature of the transmission grid. Integration also will provide the Company's operations, planning and energy supply experts with additional tools to address reliability and reduce stresses on the system.

Several Public Staff witnesses expressed concern in pre-filed testimony that the Company does not have a reliability problem to solve. There is no question but that Dominion has provided reliable service to its North Carolina retail customers. For that reason, there is a legitimate question abou the extent to which integration will improve Dominion's reliability. However, when questioned about the assessment of the Company's experts that reliability would improve, the Public Staff agreed at the hearing that PJM will provide some additional reliability benefits to the Company's system. In particular, Public Staff witness Dr. Morey stated that PJM will provide reliability benefits, and agreed with the list of benefits provided by witnesses Thompson and Bailey in rebuttal testimony, while questioning only the "value" of the benefits. Public Staff witnesses Floyd and Rosenberg also acknowledged the reliability benefits of integration. Any skepticism expressed by Public Staff hinged solely on the issue of whether those benefits are worth the cost. Having adopted Regulatory Conditions to hold Dominion's North Carolina retail ratepayers harmless from the net costs resulting from Dominion's integration into PJM, the Commission finds that there is some level of non-quantifiable incremental benefit from PJM integration to the Company's North Carolina retail customers.

The Commission recognizes the important distinction between reliability of service to retail customers, which is measured by how often and for how long a retail customer loses power, and reliability of the transmission system. The evidence in this proceeding demonstrates that, when the Company's operating and planning experts consider reliability, they are concerned not only about lights going out for the Company's North Carolina retail customers; but also about avoiding situations where the transmission system is stressed to the point where system collapse may occur. The reliability benefits of PJM integration are not predicated upon solving any particular reliability problem, but instead arise from on-going enhancements of transmission system operations. In response to cross-examination by the Public Staff, Mr. Thompson explained the difference between these two types of "reliability" and the tools that PJM will provide his team to better address transmission system issues.

The Commission agrees that the Company's focus on reliability includes both preventing loss of power for its North Carolina retail customers <u>and</u> avoiding situations in which the transmission system is close to collapse. Company witness Bailey explained the difference between day-to-day reliability for retail customers as compared to planning for a reliable transmission system. Witness Bailey testified that, while the Company is proud of its 99.9 percent reliability record, "reliability" from a planning perspective is a bigger picture and that there are events that take place on the transmission system that may or may not impact those 99.9 percent numbers but still affect reliability.

Mr. Bailey testified that, as an example, taking a transmission line out of service has a certain and immediate impact on the Company's transmission facility. He noted that such an action would cause the loading on other lines to go up, and if limitations on those lines were exceeded, it would create a problem that would have to be addressed such as increasing the capability of those facilities, which in turn creates a need to also look at the generation pattern or generation within the Company's service territory. Witness Bailey explained that his team would then have to "jockey that generation back and forth to see if we've got an overloaded facility," determine whether his team can bring that facility back down within normal ratings and, if not, to create an expansion plan. Witness Bailey noted that as that line loads up, the system becomes more and more unreliable and that the next event makes it even less reliable. Witness Bailey then explained that, under the larger PJM planning footprint, his team would be in a better position to deal with those facilities and would have more generation to control those overloads and possibly eliminate some upgrades that would be needed if the system is planned separately as it is today.

Mr. Thompson described how any number of events may jeopardize the reliability of the grid, even if such events do not result in a blackout. These include not performing system analysis in real time, not knowing of contingency overloads on neighboring systems, lack of awareness of flows through the transmission system, and limited curtailment authority. The evidence in this proceeding establishes that PJM's back-up system and regional views may be able to help prevent these types of problems from occurring. The Commission concludes that the Company presented credible evidence that there are issues and problems that can occur on the transmission system for which it is responsible that do not typically result in a blackout. Additionally, the evidence tends to show that PJM provides a backup to the system analysis conducted by the Company, including improved provision of information on generators within the Company's borders or in a neighboring utility, on single contingency overloads of transmission facilities that could impact the Company, and on loop flows on the Company's system.

The Commission recognizes, and the evidence establishes, that PJM provides tools that may help improve reliability that the Company, as a single control area operator, does not possess. At the hearing, the Public Staff acknowledged that there could be reliability problems on the Company's transmission system, such as a voltage problem or a problem on the AEP transmission system, that affects the Company which would not cause a loss of service to the Company's North Carolina retail customers. These problems would also not be reflected in the system average interruption duration index (SAIDI) or system average interruption frequency index (SAIFI) shown in Public Staff Cross-Examination Exhibits 1 and 2. In addition, Public Staff witness Morey agreed that it is possible to have a violation of a reliability criterion on the transmission system with no impact on the Company's retail customers in North Carolina.

The evidence also demonstrates that PJM integration may improve reliability by using LMP to address transmission congestion, which the Commission recognizes may be an improvement over the current TLR methodology for curtailing wholesale power transactions that affect reliability. Company witness Thompson's testimony establishes that the LMP method will enhance reliability of the transmission system because it produces a faster, more efficient means of relieving transmission congestion. Witness Thompson explained that LMP is more reliable because it can "go in and curtail generation across the constraint for pretty close to what's needed once the constraint is relieved." On redirect, Mr. Thompson further discussed the improvements in the timing of curtailment requests under LMP and the reasons he believes that the LMP process will enhance reliability over the current TLR method. PJM witness Bowring, like PJM witness Hinkel and Company witnesses Thompson and Morgan, testified that "LMP is superior to TLR as a congestion management tool ... expressly designed to produce a more efficient overall dispatch of generation to resolve congestion." Public Staff witness Rosenberg admitted that there are efficiencies to be gained by switching from TLR to LMP, and he further stated that he is not in a position "to support or contradict [Mr. Hinkel's testimony about LMP] in any way." Thus the evidence establishes that LMP may be superior to TLR as a congestion management tool and might result in a more efficient overall dispatch of generation to resolve congestion.

The evidence tends to show that "reliability" is more than a measure of how many minutes a year a customer's lights are out, but rather is the ability of a transmission system to withstand events and how long it takes to address problems. The evidence, and specifically Mr. Bailey's testimony, suggests that whereas a system planned individually may become unreliable when it gets to the second or third event, under the PJM footprint the same situation may allow the Company's transmission system to withstand four, five or six events, which is a notable reliability improvement in planning compared to today. The Commission notes that Public Staff acknowledged that reliability goes well beyond merely "keeping the lights on," and that a reliability problem on the transmission system may not affect retail customers.

Although Dominion currently provides reliable service in its North Carolina service territory, integration may provide incremental enhancements to the reliability of the service Dominion provides in North Carolina. Accordingly, the Company's Application and the evidence in this proceeding demonstrate that the integration of the Company into PJM may provide incremental non-quantifiable benefits to the Company's North Carolina retail customers by improving the reliability of the transmission grid.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is found in the Application and the testimony of Company witness Bailey.

The Company's Application and the testimony of Company witness Bailey tend to show that PJM provides the Company's North Carolina retail customers with the non-quantifiable benefit of optimizing system planning through participation in PJM's Regional Transmission Expansion Protocol Process (RTEP Process), while maintaining the expertise of the Company's local transmission planning group. The evidence suggests that participation in the RTEP Process may improve the long-term reliability of the Company's overall transmission system by enhancing the reliability of the transmission grid that serves North Carolina. Dominion's integration into PJM will permit a broader and more regional view of the transmission infrastructure, which should improve long-term reliability.

Although Dominion currently participates in regional assessments – VST, VAST, and VEM – Company witness Bailey testified that there is a key difference between the Company's participation in these "assessment" groups and the improved planning that integration into PJM will provide. Witness Bailey explained that the "assessment" approach is a mere diagnostic tool, whereas the PJM planning process broadens the scope of the area being considered and may also result in an actual proposal for alleviating the problems identified in such assessments.

As Company witness Bailey explained in his rebuttal testimony, the Dominion service area is not an isolated system, and loop flows (i.e., flows on one system caused by generation on adjacent or remote systems) are continuously present on all networked transmission facilities owned by the Company and providing service to North Carolina load. Thus, what happens or does not happen elsewhere on the interconnected regional grid has important implications for the Company's North Carolina service area.

The evidence also suggests that PJM's open stakeholder planning process provides a vehicle for the Company to address the needs of its transmission system over the long term. Company witness Bailey testified that the regional process would improve the Commission's ability to participate at the front end of that process, as opposed to the current system, in which opportunities to participate are more limited and less formal. The Public Staff recognized that the Commission will have more of a role as a stakeholder in the regional process, while acknowledging the Commission's ongoing authority to order planning and to continue to exercise its authority to regulate service quality. Witness Bailey also noted that three of the four companies with which Dominion is interconnected have become members of PJM. Therefore, the Company's integration into PJM will allow the Company to participate in a unified, formalized planning process that already includes all but one of its neighboring systems.

Once again, the Commission concludes that, while Dominion adequately conducts system planning activities now, PJM's planning process may provide incremental benefits by broadening the scope of the planning process through the ability to address off-system transmission-related issues. As a result, the Commission concludes that the evidence in the record supports the conclusion that integration into PJM should provide non-quantifiable planning benefits to the Company's North Carolina retail customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is found in the Company's Application and the testimony of Company witness Morgan.

Company witness Morgan testified that PJM's transparent market structure enables better economic decisions relating to the Company's need to meet its load requirements with Company resources and purchases and that PJM creates a better environment for managing risks inherent in the wholesale market than that which exists today. Markets exist today for the Company's fuel, capacity and energy, which are important for serving the Company's North Carolina load. Witness Morgan testified, however, that the wholesale markets in which the Company currently operates are marked by structural inefficiencies and a lack of transparency, stating that "[t]hese weaknesses inhibit the [C]ompany's ability to service our load at the lowest cost." Mr. Morgan further testified that "the PJM platform corrects these structural inefficiencies, provides immediate benefits to our customers, and creates a stable platform to address the future development of the interconnected electric grid." In addition, Mr. Morgan noted that "In PJM, transactions will be easier, dispatch will be optimized across a wider area, transmission barriers will be lifted, and each of these facts will enhance [the Company's] ability to get the most efficient results for our North Carolina retail customers."

Integration into PJM will provide Dominion with additional access to large-scale energy markets. Company witness Morgan testified that the increased access to a broader pool of generation capacity will provide for more reliable, cost-effective, long-term planning and more reliable real time operations. Witness Morgan further testified that the Company currently acquires capacity in non-visible and non-standardized markets. Integration with PJM will provide the ability for Dominion to purchase capacity when there is an economic choice of serving the Company's customers in a visible market, with increased assurance that the capacity will be available and deliverable to the Company's load.

Mr. Morgan affirmed in his testimony that PJM integration will improve transmission access to supply options outside the Dominion transmission zone by eliminating pancaked transmission rates within the PJM footprint and decreasing reliance on third-party transmission providers. In day-to-day operations, PJM's wide geographic footprint provides increased access to reserve power. Specifically, there is a pool of approximately 168,000 MW of generation capacity within PJM which can be dispatched to assist in serving load when necessary. Without PJM, the Company relies upon its own assets and more limited purchases from neighboring utilities.

The Commission concludes that the easier access to off-system generation resulting from PJM integration should provide Dominion with additional power supply options. Although Dominion has provided reliable and reasonably-priced service in North Carolina and although there are risks associated with participation in PJM's markets, enhanced access to additional generation has some incremental benefit for customers. Accordingly, and based on the evidence in the record, the Commission concludes that the Company's integration into PJM will somewhat improve the Company's ability to secure generation resources for the benefit of the Company's North Carolina retail customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence for this finding is found in the testimony of Company witnesses Schwab, Thompson, Bailey, Morgan, and Payne and Public Staff witness Morey.

The Public Staff argued that a "carve out" of North Carolina retail service from PJM's tariffs may be necessary to protect Dominion's North Carolina retail ratepayers from the potential adverse effects of the Company's integration with PJM. As Company witnesses Schwab, Thompson, Bailey, Morgan and Payne all explained and as the evidence demonstrates, implementing a physical "carve out" would require the Company to keep North Carolina transmission facilities out of the PJM tariff. As a result, no customers in the Company's North Carolina service territory – retail or wholesale – would receive the incremental benefits of PJM integration described above.

According to Company witnesses Thompson, Bailey, Morgan and Payne, implementing a physical "carve out" would increase the cost to serve load in North Carolina without any increase in benefits. In other words, a physical "carve out" would increase the cost to provide the same level of service that the Company provides today. In contrast, integration into PJM will improve reliability, optimize system planning and enhance resource adequacy. These reliability benefits represent immediate and continuing benefits to North Carolina retail customers upon integration of the Company into PJM. Accordingly, Dominion argues that a physical "carve out" would not be in the best interests of the Company's North Carolina retail customers. Indeed, any such physical "carve out" would be wholly inconsistent with the way the Company operates today. As Company witness Morgan explained, the Company operates its units to serve all of its load (in Virginia and in North Carolina) on an aggregate basis in order to serve its load in the most efficient and cost-effective manner possible.

A number of other parties urged the Commission to reject a physical "carve out," including CUCA, Duke, and NCEMC. CUCA, for example, cited testimony stating that a physical "carve out" would be costly and would require duplicate capabilities without additional benefits. In addition, CUCA noted that several Dominion witnesses explained that a physical "carve out" of Dominion would not provide transmission reliability benefits and would instead create additional seams, additional operational complexity, and a new control area and require additional operators. CUCA further argued that much of the Public Staff's criticism of and resistance to the proposed transfer is misplaced because the criticism and resistance are based upon the success of Dominion as an independent integrated utility. Dominion can no longer remain an integrated utility without participating in PJM, however, because the VSCC has already approved the transfer of functional control of Dominion's Virginia transmission assets to PJM. Lastly, CUCA argues that the Public Staff's lauding of the success of Dominion's integrated operations for reliability and other purposes suggests to some extent that Dominion's retail ratepayers would be served best if Dominion were permitted to remain an integrated utility, and the only means of accomplishing that, in light of the VSCC's decision, is to grant Dominion's Application.

Duke also urges the Commission to reject a physical "carve out." Duke states that, absent the sale of a portion of Dominion's transmission system or other extraordinary circumstances, any transmission system which is designed and operated as a whole should not in any way be "split." Duke believes that any "carve out" which might impact negatively upon the operational or economic efficiency of the entire Dominion system would benefit no party, certainly not the ratepayers of North Carolina, and should be carefully avoided. Duke notes that, should the Commission desire financial protections for Dominion's North Carolina customers, the revised JOS filed by Dominion and PJM appears to be intended to protect those customers from potential adverse cost impacts resulting from the assumption of control of Dominion's transmission system by PJM. Duke believes that financial protection of the character presented by the revised JOS is a more promising means of effecting the transition of a system to an organized market such as PJM.

Lastly, NCEMC questions the exact relief sought by the Public Staff in a "carve out" – physical or financial. If it is intended as a financial carve out, as suggested by Public Staff witness Morey's testimony, Dominion claims that the revised JOS is a financial "carve out" designed to protect Dominion's North Carolina ratepayers. On the other hand, if it is a physical "carve out" which the Public Staff seeks, NCEMC argues that such an approach would be complicated and costly. NCEMC believes the testimony demonstrates that creating a new control area would generate new costs to be borne by Dominion's North Carolina customers, both retail and wholesale. NCEMC notes that there are other adverse impacts from a physical "carve out" besides cost, one of the primary ones being the creation of additional seams. The Public Staff's own witness, Dr. Morey, testified, "I have to say creating a separate control – creating another control area, when all the discussion in this country is about reducing the control – the number of control areas, it does seem to be counter-intuitive, counter-logical."

The Commission concludes that the revised JOS together with the additional Regulatory Conditions adopted herein provides more benefits to the Company's North Carolina retail consumers than a physical "carve out." A physical "carve out" would create a number of new economic and operational issues which are best avoided. The requirement that Dominion hold its North Carolina retail ratepayers harmless provides the incremental qualitative benefits of PJM integration (including enhanced reliability, larger scale planning and somewhat easier access to additional generating resources) to the Company's North Carolina retail customers while insulating those customers from PJM-related costs. As a result, the approach adopted by the

Commission seeks to avoid the problems associated with a physical "carve out" while providing ratepayers sufficient insulation from the risks and costs inherent in integration.

The Commission concludes that a physical "carve out" of the Company's North Carolina service area is not necessary and is not in the best interest of the Company's North Carolina retail ratepayers

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The evidence for this finding is found in NCEMPA's contract with the Company, as well as the FERC Order Establishing PJM South, Subject to Conditions.

The North Carolina Eastern Municipal Power Agency submitted the affidavit of Donna S. Painter arguing that the benefits provided to the Company's retail customers in North Carolina should be extended to the retail customers of NCEMPA's participants. However, this Commission does not regulate the rates and terms of service provided by North Carolina municipal electric utilities. That authority is vested in the FERC. As such, the Commission lacks the authority to order the relief sought by NCEMPA, and accordingly, NCEMPA's requests are rejected.

Dominion provides wholesale transmission services to NCEMPA under a contract on file with and subject to the exclusive jurisdiction of FERC. In its October 5, 2004 order conditionally accepting the Company's application to form PJM South, the FERC granted grandfathered status to the NCEMPA contract (i.e., not requiring that the contract be replaced with service under the PJM OATT). Thus, any changes to the terms of service under the Company's contract with NCEMPA (and any terms of service for services PJM would provide to NCEMPA) are beyond the scope of this Commission's authority as they are exclusively within the jurisdiction of the FERC.

Therefore, the Commission concludes that the Commission lack's authority to consider NCEMPA's claims.

IT IS, THEREFORE, ORDERED as follows:

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:

a. As stated in the testimony of Dominion witnesses, Dominion's North Carolina retail customers shall continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law using the same ratemaking methodology as that employed by this Commission as of the time of Dominion's joining PJM notwithstanding Dominion's integration into PJM or decision to participate in any capacity or energy market administered by PJM; that is, under no circumstance(s) or event(s) shall the costs of generation and transmission, among other things, included in Dominion's N.C. retail rates be greater than the lesser of (1) such costs determined on the basis of historical, embedded costs, calculated consistent with the Commission's currently existing rate base, rate-of-return ratemaking practices and procedures, or (2) the marginal costs of generation and transmission supplied into or purchased from PJM;

b. Dominion shall continue to serve its native load customers in North Carolina with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements before making power available for off-system sales;

c. Dominion shall take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with the same (or higher) superior level of bundled electric service as that provided prior to Dominion's integration with PJM, including, for example, reliable generation, transmission, and distribution service; minimization of power outages, efficient restoration of service; and responsive customer service;

d. Dominion shall not include in base rates: (a) PJM administrative fees or any replacement mechanism for such fees approved by the FERC; (b) PJM transmission congestion costs or revenues from PJM for financial transmission rights (FTRs) or auction revenue rights (ARRs) or any replacement mechanism for such cost and revenues approved by the FERC; (c) any increase in transmission service charges to the Company resulting solely and directly from a change in rate structure from license plate rates to another rate structure for recovering the embedded costs of transmission facilities used to provide Network Integration Transmission Service; (d) any increase in transmission charges resulting from charges associated with regional transmission expansion costs that are chargeable under the PJM Tariff to the Dominion zone, and which are not included in the Company's transmission revenue requirement; or (e) any increase in transmission costs to the Company or any revenues resulting from the FERC's orders in Docket Nos. ER04-829 and ER05-6, <u>et al.</u> imposing the Seam Elimination Cost Adjustments (SECAs);

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; and

f. Neither PJM, Dominion nor any affiliate shall assert in any proceeding in any forum that federal law, including, but not limited to, the Public Utility Holding Company Act of 1935 (PUHCA) or the Federal Power Act (FPA), preempts the Commission from exercising such authority as it may otherwise have (or would have were Dominion not a member of PJM) under North Carolina law to set the rates, terms, and conditions of retail electric service to Dominion's North Carolina retail ratepayers and that Dominion shall bear the full risks of any such preemption;

(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;

(3) That Dominion and PJM shall, consistent with the above additional regulatory conditions, comply with the terms of the Settlement Agreement with Progress filed December 16, 2004. Dominion and PJM shall, with regard to all of the signatories thereof, honor, and discharge Dominion's obligations pursuant to, the various VACAR and other regional agreements referenced in the Settlement Agreement, including, but not limited to the VACAR Reserve Sharing Agreement, as Dominion would have been so obligated to do prior to Dominion's integration with PJM. In fulfilling this condition, Dominion and PJM shall continue to follow the practices and operating procedures around these agreements that have been customarily observed by the participants but do not necessarily exist in written form; and

(4) That Dominion shall continue to comply with all regulatory conditions and codes of conduct previously imposed by the Commission;

2. That the conditions imposed by the Commission shall remain in effect for a period of not less than ten (10) years from the date of Dominion's integration into PJM and continuing thereafter indefinitely and until further Order of the Commission;

3. That Dominion shall notify the Commission in writing on or before April 20, 2005, and before taking any further action to transfer operational control of Dominion's transmission facilities located in the State of North Carolina to PJM, that it accepts and agrees to be bound by the conditions imposed by the Commission on its approval of the Company's Application in this proceeding and the statements and assertions concerning the Commission's jurisdiction set forth herein; and

4. That this Order shall not serve as precedent with respect to any future request by a utility to join an RTO or otherwise transfer operational control over its transmission facilities.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Commissioner J. Richard Conder dissents.

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DOCKET NO. E-22, SUB 418

COMMISSIONER J. RICHARD CONDER, DISSENTING: I strongly dissent from the majority's conditional approval of Dominion's application for authority to transfer functional control of its transmission assets to PJM Interconnection, LLC.

This issue, and Dominion's application, has come before this Commission solely due to action taken by the Virginia General Assembly which mandated restructured, unbundled electric rates in Virginia and required that each electric utility shall join or establish a regional transmission entity. Subsequently, Dominion moved ahead in this direction in Virginia by requesting approval from the VSCC for authority to join PJM and also requested authority from this Commission since its transmission system serves both states.

Although Dominion's application before the VSCC showed a 10-year quantifiable benefit for Dominion's membership in PJM of $557.2 million for all customers in the Dominion service area, including Dominion's North Carolina customers, the study also shows that the net present value of the quantifiable benefits and costs for Dominion's North Carolina ratepayers from 2005 through 2014 would be a negative $1.8 million. During those years, Dominion's North Carolina retail customers would pay an additional $1.8 million for their electric service, without receiving any corresponding quantifiable benefits. Further, as noted in the Order, the Public Staff's witnesses presented evidence that the quantifiable costs may be considerably larger than the $1.8 million, possibly as high as $4.1 million to $10.1 million.

Also as discussed in the Order, Dominion's cost/benefit study shows that North Carolina's retail consumers will pay increased fuel costs of approximately $2.8 million during the period covered by the study. This increase will result from Dominion's increased use of purchased power to serve its retail customers.

Of even greater importance to retail customers, the transfer could result in the loss of a substantial portion of the Commission's regulatory authority, causing both current and future potential harm to Dominion's North Carolina ratepayers. As expressed in the public policy statement of G.S. § 62-2, the General Assembly believes that the most reliable and efficient means to provide electric service to retail consumers is by fully integrated public utilities operating under regulated rates and services. An integral part of North Carolina's retail rate structure is that public utility rates include the costs of generation, transmission and distribution, and that these costs are fully bundled into one single rate.

The transfer of control for transmission and generation facilities from Dominion to PJM would create a strong possibility that a significant portion of the Commission's legal authority to regulate certain aspects of service to retail consumers in North Carolina would be shifted to the FERC.

As discussed in the Order, PJM is an RTO approved and regulated by the FERC, and the FERC has authority under the FPA to set PJM's transmission rate for unbundled wholesale transmission service and rates for wholesale sales made through PJM's wholesale power market. The line that divides the Commission's and the FERC's regulatory authority between retail transmission and energy rates, and wholesale transmission and energy rates is fairly distinct today, but could become blurred by Dominion's membership in PJM, since sales in the PJM market are made at FERC-approved market based rates. Dominion's cost of producing electricity to serve North Carolina consumers would no longer be based on Dominion's actual costs, but rather on PJM's market-based rates. Therefore, the Commission's authority to set cost-based energy rates for Dominion's North Carolina retail customers could well be preempted by higher PJM market-based rates set by the FERC.

Also as noted, PJM's transmission rates are higher than Dominion's. Thus, Dominion's lower transmission rates for services to its North Carolina retail customers could be preempted by the higher PJM rates set by the FERC. In effect, Dominion's membership in PJM could result in Commission loss of state law regulatory authority over both Dominion's generation and transmission services and the rates paid by North Carolina consumers for those services. Once the operation of these assets have been transferred, they are under the direction and control of an entity (PJM) over which this Commission exercises no authority. I applaud our attempt to impose conditions, but I cannot fathom how we can enforce those conditions when we have allowed the only entity over which we retain some authority (Dominion) to give operational control over those assets to an entity we cannot govern. I believe the conditions give us a false sense of security and in the end give us only an illusory means to ensure reliable and cost effective electric service for northeastern North Carolina.

As stated in the Order, the risks of Dominion's membership in PJM should be borne by Dominion, not Dominion's North Carolina customers. The conditions set forth in this Order by the majority may not fully protect Dominion's North Carolina retail customers from all potential risks and harms from the proposed integration.

In my opinion, Dominion's application to join PJM does not meet the public convenience and necessity standard. The costs to Dominion's retail ratepayers clearly exceed the quantifiable benefits and approval of this transfer in control will likely result in the loss of a substantial portion of the Commission's and the State of North Carolina's regulatory authority, possibly causing current and future harm to Dominion's retail ratepayers. The conditions placed on Dominion and PJM in this Order do not necessarily insulate Dominion's retail ratepayers from currently unforeseen circumstances, concerns and issues that might arise from this step into unknown and unchartered waters.

\s\ J. Richard Conder
Commissioner J. Richard Conder

DOCKET NO. G-9, SUB 504
DOCKET NO. G-44, SUB 17

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Application of Albemarle Pamlico	)	
Economic Development Corporation and	)	ORDER APPROVING
Piedmont Natural Gas Company, Inc. to	)	APPLICATION
Engage in a Business Transaction	)	

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on June 23, 2005

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

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

Kim R. Cocklin, Piedmont Natural Gas Company, Inc., 1915 Rexford Road, Charlotte, North Carolina 28211

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 Albemarle Pamlico Economic Development Corporation:

Thomas P. Nash, Trimpi, Nash & Harman, 200 N. Water Street, Suite 2A, Elizabeth City, North Carolina 27909

For 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 Using and Consuming Public:

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

For the Using and Consuming Public:

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On April 1, 2005, Piedmont Natural Gas Company, Inc. (Piedmont) and Albemarle Pamlico Economic Development Corporation (APEC), (Piedmont and APEC are hereinafter collectively referred to as the Applicants), filed an application seeking: (1) authorization and approval of the acquisition by Piedmont from APEC of APEC's interest in certain shares of Eastern North Carolina Natural Gas Company (EasternNC) as set forth in the Stock Purchase Agreement (SPA), (2) authorization of the assignment by APEC and the assumption by Piedmont of the EasternNC Rights and Obligations set forth in the SPA, (3) approval of the merger of EasternNC into Piedmont with Piedmont being the surviving corporation (Merger), (4) authorization of the transfer to Piedmont of all of EasternNC's rights and obligations under all certificates of public convenience and necessity issued by the Commission to EasternNC, (5) authorization of Piedmont to commence natural gas service in all areas of North Carolina previously certificated to EasternNC under the rolled-in rates, terms and conditions of service approved in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15, (6) authorization for EasternNC to discontinue natural gas service in North Carolina upon the effective date of the Merger, (7) authorization for Piedmont to make the appropriate changes in its policies and procedures necessary or appropriate to effect the Merger, (8) approval to transfer to Piedmont, without modification or alteration, all authorizations granted to and obligations of EasternNC with respect to the issuance, use, accounting and reporting of bond funds utilized to construct portions of the EasternNC system pursuant to G.S. 62-159 and Commission Rules R6-90 through R6-94, (9) authorization for Piedmont to do business under the trade names Eastern North Carolina Natural Gas and EasternNC, and (10) a grant of such additional authorizations and/or waivers as may be necessary or appropriate to effectuate the transactions set forth herein. Exhibits supporting the Joint Application were filed with the Applicants' Petition, as was the prepared direct testimony of David J. Dzuricky and Mitch Renkow, Ph.D.

On April 25, 2005, Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene in this proceeding, which was allowed by Commission Order dated May 11, 2005.

On April 27, 2005, the Commission issued its Order Scheduling Hearing, Establishing Procedural Deadlines, and Requiring Public Notice (Scheduling Order). This Order established a hearing date of June 23, 2005, established discovery procedures, set forth dates for the filing of Public Staff and Intervenor testimony, and required the Applicants to give notice to their customers of the hearing on this matter. In the Scheduling Order, the Commission waived the requirement of a market power study.

On May 5, 2005, the Attorney General filed his Notice of Intervention in this proceeding pursuant to G.S. 62-20.

On June 1, 2005, Kevin M. O'Hara filed substitute direct testimony on behalf of the Applicants. Mr. O'Hara's testimony was filed for the purpose of substituting Mr. O'Hara for Mr. David Dzuricky as a witness for the Applicants. This substitution was necessitated by the fact that the hearing date set by the Commission fell on a date on which Mr. Dzuricky had long standing arrangements to be out of the country. Mr. O'Hara's substitute direct testimony was the same as Mr. Dzuricky's in all material respects.

On June 3, 2005, CUCA filed its direct testimony of Kevin W. O'Donnell. On the same date, the Public Staff filed the direct testimony and exhibit of James G. Hoard.

On June 8, 2005, Piedmont filed a Motion for Admission to Practice before the Commission on behalf of Kim R. Cocklin, Piedmont's General Counsel, which was granted by Commission Order dated June 9, 2005.

On June 16, 2005, the Applicants filed the prepared rebuttal testimony of Kevin O'Hara.

No other party filed testimony.

On June 23, 2005, this matter came on for hearing as scheduled in Raleigh. No public witnesses appeared. The prefiled testimony and exhibits of the following witnesses were received into evidence and/or admitted into the record:

For the Applicants: Kevin M. O'Hara, Vice President of Business Development and Ventures of Piedmont Natural Gas Company, Inc., and Mitch Renkow, Ph. D., Professor of Agricultural and Resource Economics at North Carolina State University.

For the Public Staff: James G. Hoard, Assistant Director, Accounting Division.

For CUCA: Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.

Based on the testimony and exhibits received into evidence, the record in this proceeding as a whole, and the Commission's records in general, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a corporation organized and existing under the laws of the State of North Carolina authorized to engage in the business of transporting, distributing and selling natural gas and currently engaged in providing such services to approximately 675,000 customers in North Carolina pursuant to certificates of public convenience and necessity previously granted by this Commission.

2. Piedmont is a public utility within the meaning of G.S. 62-3(23) and its North Carolina operations are subject to the jurisdiction of this Commission.

3. APEC is a corporation organized and existing under the laws of the State of North Carolina. APEC was formed for the purpose of establishing EasternNC and currently is an equity owner of EasternNC.

4. EasternNC is a corporation organized and existing under the laws of the State of North Carolina authorized to engage in the business of transporting, distributing and selling natural gas and currently engaged in providing such services to approximately 900 customers in North Carolina pursuant to certificates of public convenience and necessity previously granted by this Commission.

5. EasternNC is a public utility within the meaning of G.S. 62-3(23) and its North Carolina operations are subject to the jurisdiction of this Commission.

6. Piedmont is the owner (of record and beneficially) of 50 percent, namely 500 shares, of the outstanding voting common stock of EasternNC.

7. APEC is the owner (of record and beneficially) of the remaining 50 percent, namely 500 shares, of the outstanding voting common stock of EasternNC.

8. Applicants are lawfully before the Commission pursuant to G.S. 62-111 with respect to the relief sought in their application.

9. The Applicants' application, testimony, exhibits, affidavits of publication and public notices are in compliance with the procedural requirements of the General Statutes, the Rules and Regulations of this Commission, and the Commission's prior Orders in this proceeding.

10. In this proceeding Applicants seek: (1) authorization and approval of the acquisition by Piedmont from APEC of APEC's interest in certain shares of EasternNC as set forth in the SPA, (2) authorization of the assignment by APEC and the assumption by Piedmont of the EasternNC Rights and Obligations set forth in the SPA, (3) approval of the merger of EasternNC into Piedmont, with Piedmont being the surviving corporation, (4) authorization of the transfer to Piedmont of all of EasternNC's rights and obligations under all certificates of public convenience and necessity issued by the Commission to EasternNC, (5) authorization for Piedmont to commence natural gas service in all areas of North Carolina previously certificated to EasternNC under the rolled-in rates, terms and conditions of service approved in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15, (6) authorization for EasternNC to discontinue natural gas service in North Carolina upon the effective date of the Merger, (7) authorization of Piedmont to make the appropriate changes in its policies and procedures necessary or appropriate to effect the Merger, (8) approval to transfer to Piedmont, without modification or alteration, all authorizations granted to and obligations of EasternNC with respect to the issuance, use, accounting and reporting of bond funds utilized to construct portions of the EasternNC system pursuant to G.S. 62-159 and Commission Rules R6-90 through R6-94, (9) authorization for Piedmont to do business under the trade names Eastern North Carolina Natural Gas and EasternNC, and (10) a grant of such additional authorizations and/or waivers as may be necessary or appropriate to effectuate the transactions set forth therein.

11. In order to obtain Commission approval of the acquisition by Piedmont of the remaining outstanding common voting stock of EasternNC, the merger of EasternNC into Piedmont, the acquisition by Piedmont of all requisite certificate authority needed for Piedmont to serve EasternNC's customers, and all of the associated relief sought in the application, the Applicants must demonstrate that the proposed business transactions between Piedmont and APEC are justified by the public convenience and necessity.

12. Upon the closing of the transactions set forth in the SPA, Piedmont will acquire full ownership of all outstanding voting common stock of and complete operational control over EasternNC.

13. Piedmont is an experienced and capable natural gas local distribution company that is prepared to assume the full certificate and service obligations of EasternNC.

14. Piedmont's acquisition of the remaining 50 percent of outstanding voting stock of EasternNC, as contemplated by the SPA, will not serve to materially increase Piedmont's market power or act to reduce competition within the natural gas sales and transportation markets in North Carolina.

15. The expected overall benefits of Piedmont's acquisition of the remaining 50 percent of outstanding voting stock of EasternNC, and the merger of EasternNC into Piedmont, outweigh the expected overall costs, harms, and risks associated with these transactions.

16. Piedmont's acquisition of the remaining 50 percent of outstanding voting stock of EasternNC, and the merger of EasternNC into Piedmont, are consistent with the public interest and justified by the public convenience and necessity.

17. It is appropriate that Piedmont be responsible for and assume all rights and obligations of EasternNC under G.S. 62-159 and Commission Rules R6-90 through R6-94 upon consummation of the business transactions proposed in the SPA and Applicants' application.

18. It is appropriate that Piedmont account for and report on the status of the economic feasibility of that portion of the EasternNC system funded with public bonds in the manner and form recommended by the Public Staff.

19. It is appropriate that the operations, cost of service, rate base, and revenues of EasternNC be integrated into the larger Piedmont system following consummation of the business transactions proposed in the SPA and Applicants' application.

20. The precise form of this integration and the specific rates, terms and conditions pursuant to which service shall be provided to customers by Piedmont following consummation of the transactions authorized herein shall be determined by the Commission in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15.

21. The additional relief sought by the Applicants is necessary and appropriate for consummation of the transactions set forth in the SPA and approved herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-7

The matters addressed in Findings of Fact Nos. 1 through 7 are jurisdictional, informational and/or procedural in nature and are not contested by any party. They are supported by the Petition and the exhibits thereto, the testimony and exhibits of the various witnesses, the records of the Commission in this and other proceedings and the Affidavits of Publication filed with the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The basis for these findings is contained in the provisions of G.S. 62-111, in the Commission's Regulations and in its Scheduling Order in this proceeding and are not contested by any party.

These findings fundamentally recognize the propriety of the Applicants' request for Commission approval of the various transactions proposed in the Petition and the Applicants' compliance with the Commission's procedural requirements with respect to such request.

In this regard, G.S. 62-111(a) provides that:

> [n]o franchise now existing or hereafter issued under the provisions of this Chapter . . . shall be sold, assigned, pledged or transferred, nor shall control thereof be changed through stock transfer or otherwise . . . , nor shall any merger or combination affecting any public utility be made through acquisition of 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.

The Applicants' Petition indicates that it seeks, among other things, approval of the Stock Purchase Agreement through which Piedmont will acquire ownership of the remaining 50 percent outstanding voting stock of EasternNC, a regulated public utility subject to the jurisdiction of the Commission, and the subsequent merger of that public utility into Piedmont.

The Commission's Regulations and its Scheduling Order in this proceeding establish a variety of procedural requirements imposed upon the Applicants (and other parties) in this proceeding, including the provision of notice to the public of the hearing of this matter. The record indicates that the Commission's Regulations and Scheduling Order have been complied with in all material respects and no party contends otherwise.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The nature of the authorizations and approvals sought by the Applicants in this docket is set forth in the Petition as well as the testimony and exhibits of the Applicants' witness O'Hara. The nature of these requested authorizations is not disputed by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The legal standard stated in this finding of fact is found in Chapter 62 of the General Statutes and in prior decisions of this Commission and the North Carolina Supreme Court.

As was noted above, G.S. 62-111(a) requires the Applicants to demonstrate and the Commission to find that the business transactions proposed in the application are justified by the public convenience and necessity. In "adjudging the public convenience and necessity in the context of proposed transfers . . . under G.S. 62-111(a), [the Commission] must inquire into all aspects of anticipated service and rates occasioned and engendered by the proposed transfer, and then determine whether the proposed transfer will serve the public convenience and necessity." State ex rel. Utilities Commission v. Village of Pinehurst, 99 N.C. App. 224, 229, 393 S.E.2d 111 (1990), aff'd 331 N.C. 278, 415 S.E.2d 199 (1992). The public convenience and necessity "is a relative or elastic theory rather than an abstract or absolute rule" and must be determined by analyzing "[t]he facts in each case." State ex rel. Utilities Commission v. Casey, 245 N.C. 297, 302, 96 S.E.2d 8 (1957). In applying this test to the application herein, it is appropriate for the Commission to consider a wide range of factors, including (a) whether or not rates and services will be adversely affected by the proposed transaction, (b) whether expected benefits will exceed known and expected costs, (c) the expected impact on service quality, (d) the extent to which costs can be lowered and/or rates maintained or reduced, (e) the effectiveness of continuing state regulation, (f) increased ability to provide stable and reliable natural gas service, (g) the ability to rely on a more diverse gas supply, (h) the creation/availability of a more geographically diverse natural gas system, (i) the provision of a more diverse staff with greater experience in the natural gas industry, (j) the elimination of concerns over gas and electricity being provided by the same family of companies, and (k) the preservation of a strong corporate presence in North Carolina for the utility succeeding to the certificate authority. See State ex rel. Utilities Commission v. Carolina Coach Company, 269 N.C. 717, 153 S.E.2d 461 (1967); *Order Approving Merger and Issuing Securities*, Docket No. G-5, Sub 400 (December 7, 1999); *Order Approving Stock Transfer*, Docket No. E-7, Sub 427 (August 29, 1988); *Order Approving Merger and Issuance of Securities*, Docket No. E-7, Sub 596 (April 22, 1997); and *Order Approving Application*, Docket Nos. G-9, Sub 470, G-21, Sub 439, and E-2, Sub 825 (June 26, 2003). As a result, after considering the totality of the relevant circumstances, the Commission is required to approve a proposed transaction in the event that, either as originally proposed or as modified by conditions imposed by the Commission, the proposed transaction viewed in its entirely is justified by the public convenience and necessity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is set forth in the Petition, the SPA, and the testimony of the Applicants' witness O'Hara.

The Petition indicates that, under the terms of the SPA, Piedmont will acquire from APEC all of the outstanding EasternNC Shares and will assume the EasternNC Rights and Obligations under the proposed transactions. Article 2.1 of the SPA confirms this assertion. The Petition further asserts that upon the acquisition by Piedmont of the EasternNC Shares, EasternNC will be merged into Piedmont. Accordingly, upon closing of the proposed transactions, and as described in the testimony of witness O'Hara, Piedmont will own all of the equity interests in the EasternNC system on an undivided basis with Piedmont's other public utility operations within this State and EasternNC will cease to exist as an independent entity. As such, Piedmont will exercise complete control over the EasternNC system and assets upon closing of the business transactions approved herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in the Petition, in the testimony of the Applicants' witness O'Hara, and in the Commission's records as a whole.

In the Petition, the Applicants indicate that Piedmont is an experienced and capable natural gas local distribution company. That assertion is echoed in the direct testimony of the Applicants' witness O'Hara who also states:

> Piedmont has previously shown that it is ready, willing and able to assume all of the regulatory responsibilities imposed upon natural gas utilities by the North Carolina General Statutes and by the rules and regulations of the Commission

> with respect to its existing utility operations in North Carolina, and ... is ready, willing and able to do so with respect to the operations of EasternNC.

Further, the Petition and the direct testimony of witness O'Hara indicate that Piedmont is currently providing natural gas distribution service to more than 960,000 customers in three States, including 675,000 customers in North Carolina. This compares to approximately 1,000 existing EasternNC customers. This evidence is undisputed.

Based on this uncontested evidence, and an extensive history of Commission experience regulating Piedmont's North Carolina natural gas distribution operations, the Commission concludes that Piedmont is capable of assuming the certificate and service obligations of EasternNC upon consummation of the transactions proposed in this proceeding. In this regard, the Commission takes judicial notice of its similar recent conclusions regarding Piedmont's capabilities contained in its Orders in Docket Nos. G-9, Sub 466 and G-3, Sub 251 (October 8, 2002), and Docket Nos. G-9, Sub 470, G-21, Sub 439, and E-2, Sub 825 (June 26, 2003).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact is contained in the Petition, the Commission's Scheduling Order in this proceeding, and in the Commission's Order Approving Application in Docket Nos. G-9, Sub 470, G-21, Sub 439, and E-2, Sub 825.

In the Petition, the Applicants requested a waiver of the requirement to file a market power study in this proceeding. In support of that request, the Applicants cited the very small number of customers served by EasternNC and the "correspondingly small nature of the natural gas commodity and capacity arrangements utilized to serve those customers in comparison to the existing customer base and gas supply arrangements of Piedmont." The Applicants also cited the Commission's previous finding that Piedmont's initial acquisition of its existing fifty percent equity interest in EasternNC raised no market power concerns in Docket Nos. G-9, Sub 470, G-21, Sub 439, and E-2, Sub 825.

This waiver request was supported by the Public Staff and granted by the Commission in its Scheduling Order. Implicit in that ruling, and affirmatively stated here, is a determination that the Commission perceives no risk that Piedmont's acquisition of the remaining fifty percent of EasternNC's outstanding voting common stock will increase Piedmont's market power or act to reduce competition within the natural gas sales and transportation markets in North Carolina.

This conclusion is supported by the factors identified above, as well as the Commission's recent conclusion that the acquisition by Piedmont of roughly 176,000 new customers in the contiguous geographic area served by North Carolina Natural Gas (NCNG) (as compared to roughly 1,000 customers served by EasternNC) raised no market power or competitive concerns.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

The evidence for these findings of fact is found in the Petition and exhibits thereto and in the testimony of the witnesses for the Applicants, the Public Staff, and CUCA. As a general statement, the Applicants and the Public Staff support the proposed transactions and contend that the transactions are in the public interest. CUCA disagrees, based largely on concerns over possible subsidization of EasternNC's operating costs by its members.

In the cost-benefit study attached to the Petition, Piedmont identified several direct economic benefits that will accrue to ratepayers as a result of the transactions proposed in the SPA. These economic benefits consisted of approximately $205,000 in annual savings attributable to the elimination of certain management fees, director and officer liability insurance premiums, and audit fees associated with the operation of EasternNC as an independent entity, which will no longer be incurred once EasternNC is merged into Piedmont. There were no costs associated with the proposed business transactions identified in the cost-benefit study. The Petition also identified other benefits of the proposed business transactions, including enhanced performance resulting from integration of corporate functions and programs, purchasing economies resulting from a larger aggregate customer base, and business optimization through a single streamlined business structure.

Mr. O'Hara provided testimony as to the benefits of the proposed transactions. Mr. O'Hara indicated that the merger would enhance both the quality and efficiency of service to EasternNC customers by making Piedmont's more experienced and much larger employee base available to serve EasternNC customers directly. He further testified that Piedmont's much larger supply and transportation portfolio would be available to directly serve EasternNC customers, thereby increasing the flexibility of service available to those customers and, over time, reducing the costs of such service. Mr. O'Hara next testified that, over time, the acquisition of and merger with EasternNC would reduce cost-of-service based rates for EasternNC, thereby improving economic development opportunities for that portion of the State and allowing it to compete for new industrial development on a more equal basis. Next, Mr. O'Hara testified that the proposed business transactions would permit the EasternNC service territory to be served over the long term by a larger, stronger and more economically viable natural gas local distribution company, thereby enhancing the quality and sustainability of service in eastern North Carolina. Finally, Mr. O'Hara testified that the proposed business transactions would provide direct access to the developing natural gas market in EasternNC for Piedmont and would preserve ownership of and operational control over EasternNC by a North Carolina based company.

In his rebuttal testimony, Mr. O'Hara identified further anticipated benefits from the proposed business transactions, including a projected $10-20 million in avoided system strengthening costs that will result from Piedmont's ability to use the EasternNC system as an integrated part of Piedmont's overall facilities to serve customers in high growth areas of the existing NCNG distribution system.

Mr. O'Hara also indicated that benefits would accrue to Piedmont from the integration and consolidation of rates and tariffs across Piedmont's North Carolina distribution systems and that this integration and consolidation would result in enhanced customer service to all of Piedmont's North Carolina customers.

Public Staff Witness Hoard agreed that aggregate cost savings would be achieved by the merger of EasternNC into Piedmont. Mr. Hoard identified the following areas of savings he believed would accrue as a result of the proposed business transactions through the elimination of duplicative regulatory and financial reporting requirements: (1) operational efficiencies attributable to elimination of duplicative internal functioning; (2) elimination of the EasternNC Board of Directors; (3) elimination of separate financial reports; (4) elimination of separate deferred gas cost accounts; and (5) elimination of separate prudence reviews. Mr. Hoard also indicated a belief that additional cost savings may be realized through the termination of the APEC Services Agreement and the Gas Supply and Transmission Agreement.

CUCA witness O'Donnell indicated a belief that the costs of the proposed merger would outweigh its anticipated benefits. In support of this contention, Mr. O'Donnell cited the testimony of Applicants' witness Dr. Renkow expressing his concern that EasternNC may not, as a stand-alone entity, ever achieve economic viability. Based on this contention, Mr. O'Donnell argued that a roll-in of EasternNC's costs should not be permitted in this docket unless industrial customers are insulated from any rate increase attributable to such roll-in. Mr. O'Donnell also argued that Piedmont should use the existing Gas Supply and Transportation Agreement to move gas to expanding areas of the NCNG system rather than incur an annual cost of service obligation of roughly $8.8 associated with the EasternNC system. Finally, Mr. O'Donnell testified that, based on his analysis of Piedmont's rate case filing in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15, industrial transportation customers on the Piedmont system would receive a 7 percent rate increase attributable to Piedmont's acquisition of and merger with EasternNC.

As was previously stated, the public convenience and necessity standard applicable to this case is a broad public interest standard which permits the Commission to weigh all costs and benefits associated with the proposed transactions. In making this analysis, the Commission must weigh both quantifiable and non-quantifiable costs and benefits. The Commission has broad discretion in how it considers and weighs the various relevant factors.

The Commission is convinced by the evidence presented by the Applicants and the Public Staff that there are expected overall benefits to EasternNC associated with the proposed acquisition by Piedmont of the remaining 50 percent of outstanding voting common stock of EasternNC and the subsequent merger of EasternNC into Piedmont. These include discrete and quantifiable savings associated with the consolidation of the corporate and regulatory functions of Piedmont and EasternNC and the unquantifiable benefits resulting from the absorption of a small and economically challenged start-up natural gas distribution company into a much larger, experienced, and well-established company that has provided safe and reliable service to North Carolina residents for many years. Piedmont's experience and gas supply portfolio will be available to EasternNC. Further, the Commission believes that, by virtue of the tie-ins between the EasternNC and Piedmont systems, the acquisition will help Piedmont to offset, at least in part, substantial costs that it would otherwise have to incur for strengthening its system in the eastern part of its service territory. CUCA's suggestion that such benefits could be achieved more economically by Piedmont's "leasing" the EasternNC system pursuant to the existing Gas Transportation Agreement is not persuasive since this agreement terminates in 2008 and arrangements after that date are unknown.

With respect to possible rate impacts, it is important to keep in mind that no changes to the rates, terms or conditions of service applicable to either Piedmont's, NCNG's or EasternNC's existing ratepayers are proposed in this proceeding. Any future changes in such rates, terms and conditions will take place only in the context of separate proceedings. Arguments either for or against the proposed transactions based upon anticipated rate effects are speculative at this time.

In making these statements, the Commission is of course aware that Piedmont has filed a proposal for an overall increase in its rates. However, it is simply not possible to know at this time whether that proposal will result in increases or decreases to the rates of specific customer groups. It is worth noting, for example, that Piedmont has proposed to decrease both NCNG industrial transportation revenues and overall system (i.e., combined Piedmont, NCNG and EasternNC) industrial transportation revenues in the pending rate case. Thus, industrial transportation customers as a whole across both Piedmont's existing system (including Piedmont and NCNG) and its expanded system (including Piedmont, NCNG and EasternNC) would see a net decrease in revenue responsibility under Piedmont's filed rate proposal. It is important to remember that attributing a proposed increase in rates to a single factor, such as this acquisition, is problematic when viewed in the context of a larger ratemaking proceeding in which rates can be influenced by a number of factors.

Finally, in approving the proposed acquisition, the Commission has considered the viability of the EasternNC system. In November 1998, the voters of North Carolina approved issuance of $200 million in general obligation bonds to be used to facilitate the construction of facilities and the extension of natural gas service into unserved areas of the State. In providing for the use of such bonds in G.S. 62-159, the General Assembly found that the extension of natural gas service into unserved areas is in the public interest and would encourage and/or achieve various benefits for those areas and for the State as a whole. Session Laws 1998-132, Section 16. See also, State ex rel. Utilities Comm'n. v. Carolina Utility Customers Ass'n., Inc., 336 N.C. 657, 670-1, 446 S.E.2d 332 (1994) (involving G.S. 62-2(9) and G.S. 62-158). Of the $200 million in bond funds authorized by the voters in 1998, approximately $188 million was ultimately allocated for construction of the EasternNC system. There is testimony in this case that EasternNC's customer base is smaller than anticipated when this use of the bond funds was approved and that there is now a substantial probability that EasternNC will never become economically viable on its own. The Commission believes that the long-term economic viability of the EasternNC system is a matter of substantial public interest, that approval of the proposed acquisition is the best way to ensure that system's continuing viability, and that our decision will help to protect the substantial investment that the State has already made in that system.

Based on all of the foregoing, the Commission concludes that the transactions anticipated by the SPA will have net expected overall benefits and that the larger public interest of the State of North Carolina will be served by approval of these transactions. The Commission concludes that expected overall benefits from the transactions will exceed expected overall costs, harms and risks, that no negative impact on service quality is expected, that certain costs to provide service will be lower after the transactions, that this Commission will continue to have effective regulatory control over Piedmont, that Piedmont's gas system will be strengthened and more geographically diverse as a result of the transactions, that competitive concerns based on gas and electricity being provided by the same entity will not exist, and that the headquarters of Piedmont will remain in North Carolina. In light of these conclusions, the Commission believes that the transactions proposed in the SPA are in the public interest and justified by the public convenience and necessity and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-18

The evidence for these findings of fact is found in Chapter 62 of the General Statutes, the Commission's rules and regulations, the Petition, and the testimony of Public Staff witness Hoard and the Applicants' witness O'Hara.

G.S. 62-159 sets forth the requirements, processes and procedures that must be followed with respect to the utilization of bond funds for the construction of portions of the EasternNC system. These requirements, processes and procedures, as supplemented by Commission Rules R6-90 through R6-94, are continuing in nature, particularly as they relate to the potential consequences of a determination that the bond-funded portions of the EasternNC system have become economically feasible. In the Petition, the Applicants requested that "all authorizations granted to and obligations of EasternNC with respect to the issuance, use, accounting, and reporting of bond funds utilized to construct portions of the EasternNC system pursuant to G.S. 62-159 and Commission Rules R6-90 through R6-94" be transferred to Piedmont without modification or alteration. In his direct testimony, CUCA witness O'Donnell voiced concern that the Commission would lose the ability to examine the relative economics of the bond-funded portion of the EasternNC system upon closing of the proposed merger. In order to address this issue, Public Staff witness Hoard recommended that certain accounting and reporting requirements be imposed with respect to the bond-funded portions of the EasternNC system. Specifically, Mr. Hoard recommended that Piedmont provide information in the form attached as Exhibit A to his testimony on a biennial basis in order to allow the Commission to conduct an economic feasibility test of the EasternNC system. In his rebuttal testimony, Applicants' witness O'Hara accepted Mr. Hoard's recommendations and acknowledged the Company's continuing obligation to comply with both the Commission's Rules and G.S. 62-159.

The Commission has carefully considered this issue and believes that the procedures and processes outlined by Public Staff witness Hoard (and accepted by Piedmont) are sufficient to ensure compliance with both the Commission's rules and G.S. 62-159 and that EasternNC's bond fund obligations and rights should be transferred to Piedmont as part of this transaction.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-20

The evidence for these findings of fact is found in the Petition, the testimony of the Applicants' witnesses O'Hara and Renkow, the testimony of Public Staff witnesses Hoard, and the testimony of CUCA witness O'Donnell.

Section 1.42 of the SPA defines roll-in as "the setting of rates by the NCUC for natural gas service to be rendered by [Piedmont] and [EasternNC] (if [EasternNC] shall be operated as a separate entity or division of [Piedmont]) in a manner that permits [Piedmont] to (a) combine the revenues, expenses, and rate base of [Piedmont] and [EasternNC] and (b) earn a return on [Piedmont's] investment in the combined rate base."

As was explained by Public Staff witness Hoard in his testimony, approval of roll-in under this definition would not, of necessity, involve unified system-wide rates for Piedmont. He testified, "The roll-in, as defined in the agreement, is only the combination of revenues, expenses and investments for the purposes of determined [sic] rates. The agreement does not define roll-in as a customer in Elizabeth City paying the same rate as Charlotte. You could have different rates, from what I understand, in different zones, if you wanted to do that." In recognition of this fact, witness Hoard testified that the Public Staff agreed, in concept, that roll-in of the EasternNC facilities was appropriate but that the precise form of that roll-in should be addressed in the rate case.

Dr. Renkow testified that he viewed roll-in as a necessity if EasternNC was to remain an economically-viable system.

CUCA witness O'Donnell, as has been previously discussed, opposed roll-in on the grounds that it creates a risk of subsidization for existing industrial transportation customers.

The Commission has carefully considered this issue and concludes that it is appropriate for the operations, revenues, expenses, and rate base of EasternNC to be integrated into Piedmont's larger system operations, revenues, expenses and rate base, but that the specifics of such a roll-in should be addressed in the pending rate proceedings, where issues such as potential subsidization can be fully explored.[1] The Commission reaches this conclusion on several grounds. First, it will eliminate duplicative functions and costs. Second, it is generally consistent with long-standing Commission policy for revenues, expenses and rate base to be considered on a consolidated basis for a single public utility operating in North Carolina. Third, it is consistent with the provisions of Chapter 62. Fourth, based on the SPA and the testimony of the Applicants' witness O'Hara, it appears that the proposed acquisition will not proceed in the absence of a roll-in as defined in the SPA. Finally, the Commission believes that the long-term economic viability of the EasternNC system is a matter of substantial public interest and that the instant decision goes a long way toward helping to ensure that system's continuing viability.

In reaching this decision, the Commission has been mindful of the concerns expressed by CUCA witness O'Donnell regarding the subsidization of one customer or customer class by another customer or customer class and is of the opinion that such matters need to be fully investigated and explored. These matters will be given appropriate consideration in the currently pending general rate case proceedings, Docket No. G-9, Sub 499, et al.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence for this finding of fact is found in the Petition, the testimony of the Applicants witness O'Hara and the testimony of Public Staff witness Hoard.

In addition to approval of the acquisition by Piedmont of the remaining fifty percent outstanding equity interest in EasternNC and the merger of EasternNC into Piedmont, the Applicants also seek certain related authority involving the transfer of certificate authority from EasternNC to Piedmont, the respective initiation and termination of service by Piedmont and EasternNC within EasternNC's service territory, modification of Piedmont's policies and

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[1] Out of an abundance of caution, the Commission wishes to be absolutely clear as to the substance and intent of its decision in this regard. By approving the combination/"roll-in"/unification/consolidation of operations, revenues, expenses, and rate bases of the various entities into those of one surviving corporate entity as provided herein, the Commission has not ruled, explicitly or implicitly, on any issue that may exist regarding rate design, including the propriety or impropriety of any issue concerning system-wide uniform rates, geographically deaveraged rates, corporate divisional-specific rates, etc. Rather, the Commission, as provided herein, has deferred ruling on such rate design and/or cost recovery issues until such time as such matters can be fully and fairly litigated in the context of the currently pending general rate case proceeding, Docket No. G-9, Sub 499, et al.

procedures, authorization for Piedmont to do business under the EasternNC name and certain other necessary and appropriate adjustments. The Commission finds each of these requested authorizations to be appropriate and necessary to effectuate the acquisition previously approved herein. Based upon its previous findings and conclusions approving the acquisition, the Commission hereby grants each of the additional authorizations sought by Applicants to be exercised in a manner consistent with the provisions of this Order, Chapter 62 of the General Statutes, and the Commission's rules and regulations.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed acquisition by Piedmont of the remaining 50 percent equity interest in the common voting stock of EasternNC, as set forth in the Stock Purchase Agreement, is hereby approved;

2. That the proposed merger of EasternNC into Piedmont is approved;

3. That, as of the effective date of the acquisition, all of EasternNC's rights and obligations under all certificates of public convenience and necessity heretofore issued by the Commission to EasternNC shall be transferred to and vest in Piedmont;

4. That, as of the effective date of the acquisition, Piedmont is authorized to commence and EasternNC is authorized to cease providing service to EasternNC's existing customers;

5. That, on and after the effective date of the acquisition, Piedmont is authorized to make appropriate changes in its policies and procedures, consistent with this Order, Chapter 62 of the General Statutes and the Commission's rules and regulations;

6. That, following the closing of the transactions approved herein, Piedmont is authorized to do business as Eastern North Carolina Natural Gas Company or EasternNC;

7. That the rates, terms and conditions pursuant to which service shall be provided to customers following consummation of the transactions authorized herein shall be determined by the Commission in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15;

8. That the Applicants shall file a written notice in this docket within thirty (30) days after consummation of the transaction approved herein;

9. That this docket shall remain open for the purpose of receiving the notice required hereinabove; and

10. That Piedmont shall provide information on a biennial basis in the form attached to Public Staff witness Hoard's testimony as Exhibit A in sufficient detail to allow the Commission to undertake an economic feasibility test of the EasternNC system.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of August, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Ah081205.05

Commissioners Howard N. Lee and Robert K. Koger did not participate in this decision.

DOCKET NO. P-55, SUB 1550

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Complaints Against BellSouth	)	
Telecommunications, Inc. Regarding	)	ORDER CONCERNING NEW ADDS
Implementation of the Triennial Review	)	
Remand Order	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, Wednesday, April 6, 2005.

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

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BY THE COMMISSION: On February 4, 2005, the Federal Communications Commission (FCC) released its permanent unbundling rules in the Triennial Review Remand Order (TRRO), FCC Docket No. WC-04313 and CC 01-338. The *TRRO* identified a number of former Unbundled Network Elements (UNEs), such as switching, for which there is no Section 251 unbundling obligation.[1] In addition to switching, former UNEs include high capacity loops in specified central offices,[2] dedicated transport between a number of central offices having certain characteristics,[3] entrance facilities,[4] and dark fiber.[5] The FCC, recognizing that it removed significant unbundling obligations formerly placed on incumbent local exchange carriers, adopted transition plans to move the embedded base of these former UNEs to alternative serving arrangements.[6] In each instance, the FCC stated that the transition period for each of these former UNEs — loops, transport, and switching — would commence on March 11, 2005.[7]

On February 28, 2005, ITC^DeltaCom Communications, Inc. (DeltaCom) filed a letter with the Commission that it had sent to BellSouth Telecommunications, Inc. (BellSouth) on

[1] *TRRO*, ¶ 199 ("Applying the court's guidance to the record before us, we impose no section 251 unbundling requirement for mass market local circuit switching nationwide.") (footnote omitted).

[2] *TRRO*, ¶ 174 (DS3 loops), 178 (DS1 loops).

[3] *TRRO*, ¶ 126 (DS1 transport), 129 (DS3 transport).

[4] *TRRO*, ¶ 137 (entrance facilities).

[5] *TRRO*, ¶ 133 (dark fiber transport), 182 (dark fiber loops).

[6] *TRRO*, ¶ 142 (transport), 195 (loops), 226 (switching).

[7] *TRRO*, ¶ 143 (transport), 196 (loops) 227 (switching).

February 21, 2005, on behalf of itself and Business Telecom, Inc. (BTI). The letter responded to a BellSouth carrier notification letter dated February 11, 2005, in which BellSouth outlined actions it planned to take in light of the FCC *TRRO*. DeltaCom argued that the *TRRO* did not allow BellSouth to refuse UNE-P orders associated with the embedded base of UNE-P customers or orders for new UNE-P customers on its effective dates.

On March 1, 2005, MCImetro Access Transmission Services LLC (MCI) filed a Motion for Expedited Relief Concerning UNE-P Orders that set forth similar arguments to those advanced by DeltaCom in its February 28, 2005, letter. MCI asked the Commission to order BellSouth to continue to accept and process MCI's UNE-P orders after March 11, 2005.

Likewise, on March 2, 2005, NuVox Communications, Inc., KMC Telecom V, Inc., KMC Telecom III, LLC and Xspedius Communications LLC (collectively, Joint Petitioners) filed a Petition for Emergency Declaratory Ruling based on similar grounds to those set forth by DeltaCom and MCI. In addition, the Joint Petitioners alleged that they had executed a separate agreement with BellSouth through which BellSouth was required to allow access to all de-listed UNEs after March 11, 2005.

On March 3, 2005, the Commission consolidated these filings in a single docket — Docket No. P-55, Sub 1550— and ordered BellSouth to respond to the MCI and Joint Petitioners' motions by March 8, 2005. The Commission also set the dispute for oral argument on March 9, 2005.

On March 4, 2005, LecStar Telecom, Inc. filed with the Commission its February 24, 2005, responsive letter to BellSouth's February 11 carrier notification letter, and CTC Exchange Services, Inc. (CTC) filed Comments in Support and Request for Expanded Relief. On March 7, 2005, Amerimex Communications Corp. filed an Emergency Petition seeking relief similar to that sought by MCI and the Joint Petitioners, and US LEC of North Carolina, Inc. (US LEC), Time Warner Telecom of North Carolina, LP and XO North Carolina, Inc. filed a Supportive Petition.

On March 8, 2005, BellSouth sought an extension of time within which to both respond in writing to the various filings described above and to appear for oral argument. Attached to BellSouth's motion was a new carrier notification letter issued by BellSouth on March 7, 2005, in which BellSouth extended the deadline for accepting "'new adds' as they relate to the delisted UNEs until the earlier of 1) an order from an appropriate body, either a commission or a court, allowing BellSouth to reject these orders, or 2) April 17, 2005."

On March 8, 2005, the Commission issued an order rescheduling the oral argument for April 6, 2005, and granting BellSouth an extension until March 15, 2005, to respond to the various motions, complaints and letters that had been received in this docket.

On March 9, 2005, the Commission received a letter from CTC in which it advised the Commission that it would rely on its written comments and the arguments of other CLPs and accordingly would not participate in the oral argument. On the same date, the Commission received a copy of a letter from Navigator Telecommunications, LLC to BellSouth dated February 28, 2005, in which Navigator objected to BellSouth's proposed implementation of the *TRRO*.

On March 14, 2005, BellSouth moved to strike the filing by Amerimex on the grounds that the filing had not been signed by an attorney licensed to practice in North Carolina. The Commission subsequently concluded that good cause existed to grant the motion unless Amerimex cured the deficiency noted by BellSouth by March 31, 2005. Amerimex withdrew its Emergency Petition on March 22, 2005, stating that it had entered into a commercial agreement with BellSouth that mooted its Petition.

On March 15, 2005, BellSouth filed its responses to the relief sought by MCI, Joint Petitioners and the other parties listed above. On March 16, 2005, AT&T of the Southern States, LLC (AT&T) asked the Commission, to the extent it awarded any relief to the various petitioners, to award the same relief to AT&T. Prior to the oral argument, the Commission received several submissions from the parties conveying "supplemental authority" supporting their various positions.

Oral argument took place as scheduled on April 6, 2005. Counsel for various parties appeared at that time and argued their respective positions before the full Commission. At the conclusion of the argument, the Presiding Commissioner asked the parties to submit post-argument briefs and/or proposed orders. MCI, US LEC, BellSouth, Joint Petitioners, Public Staff, and CTC made post-hearing filings.

On April 15, 2005, the Commission issued a Notice of Decision and Order containing the conclusions set out below.

1. With respect to the provision of UNE-P, DS1, and DS3, the Commission declines to declare that BellSouth must provide "new adds" of these UNEs outside of the embedded customer base. Nevertheless, BellSouth must continue to process orders for the existing base of CLP customers pending completion of the transition process.

2. With respect to the issue of the provision of loop and transport, the Commission finds that the representation of BellSouth at the oral argument that it will follow the procedures outlined therefor in the TRRO renders this issue moot.

POSITIONS OF PARTIES

BellSouth argued that the FCC's ban on "new adds" of former UNEs –i.e., the addition of new customers using unbundled access to local circuit switching—was "self-effectuating" and relieved BellSouth of any obligation under its interconnection agreements to provide such "new adds" to CLPs. *See, e.g.*, TRRO, para. 3. BellSouth relied on what it believed to be the plain language of the TRRO. It argued that the FCC's new rules unequivocally state that carriers may not obtain new UNEs, and noted that the FCC had stated that there would be a transition period for *embedded UNEs* to begin on March 11, 2005, which would last for 12 months. *See*, TRRO, para. 199. The FCC made almost identical findings with respect to high-capacity loops and transport. *See, TRRO*, para. 142, 195, also 47 C.F.R. 51.319(e)(2)(i), (ii),(iii), and (iv) and 51.319(a)(4)(iii), (a)(5)(iii), and (a)(6). The FCC also said that the transition period was to apply only to the embedded customer base and does not permit CLPs to add new customers using unbundled access to local circuit switching. *Id.* There are at least a dozen instances in the TRRO where it is made clear that there are to be no new adds for these UNEs. *See*, paras. 3, 4, 142, 145, 195, 198, 227; Rules at p. 147, 148, and pp. 150-152.

BellSouth also argued that the FCC has the legal authority to implement self-effectuating changes to existing interconnection agreements. This is implied by the FCC's decision in the TRO *not* to make its decisions in that order self-executing and is recognized by case law, notably *Cable & Wireless, PLC v. FCC,* 166 F.3d 1224, 1231-32 (D.C. Cir. 1999)(*Cable and Wireless)* (*quoting Western Union Tel. Co. v. FCC,* 815 F.2d 1495, 1501 (D.C. Cir. 1987). *See, also, United Gas Improvement Co. v. Callery Properties, Inc.* 382 U.S. 223, 229 (1965)(*Callery Properties*)(agencies can undo what is wrongfully done by virtue of their orders). The FCC had also made the requisite public interest findings under the *Mobile-Sierra* doctrine[1] inasmuch as the FCC in various places noted that certain unbundling proposals constituted a disincentive to CLP infrastructure investment. Even apart from the *Mobile-Sierra* doctrine, the FCC has the authority to create a self-effectuating change because interconnection agreements are not truly "private contracts," but rather arise within the context of ongoing federal and state regulation. Numerous state commissions have rejected the relief sought by the CLPs (Ohio, Indiana, New York, California, Texas, Kansas, New Jersey, Rhode Island, Maine, Massachusetts, Delaware, Michigan, Maryland, Florida, Virginia and Pennsylvania). On April 5, 2005, the United States District Court for the North District of Georgia entered a preliminary injunction against enforcement of the Georgia Public Service Commission's order favorable to the CLPs on the same subject matter, finding a significant likelihood that BellSouth would prevail on the merits. The Court found that reliance on the *Mobile-Sierra* doctrine was unnecessary because, among other things, the FCC "was undoing the effects of the agency's own prior decisions, which have repeatedly been vacated by the federal courts as providing overly broad access to UNEs." Order, *BellSouth Telecommunications, Inc. v. MCIMetro Transmission Services, Inc.* No. 1:05-CV-0674-CC (April 5, 2005) (Georgia District Court Order).

BellSouth further maintained that CLPs are not entitled to UNE-P under state law because, even if North Carolina were not preempted by federal law, the Commission has not conducted the required impairment analysis. In any event, CLPs are not entitled to UNE-P under Section 271 of the Telecommunications Act because, among other things, there is no obligation for BellSouth to combine Section 251 and Section 271 elements, much less at TELRIC rates. Section 271 elements fall within the exclusive jurisdiction of the FCC.

As for the Abeyance Agreement between BellSouth and the Joint Petitioners (Nuvox, KMC, and Xspedius), this was a procedural agreement between BellSouth and those parties entered into in July, 2004. It provided that, during their arbitration proceeding, BellSouth would afford the Joint Petitioners "full and unfettered access to BellSouth UNEs provided for in their existing interconnection agreements on and after March 11, 2005, until such...agreements are replaced by new interconnection agreements...." This Agreement does not restrict BellSouth's rights under the TRRO. The Abeyance Agreement is limited in application to "changes of law," and the FCC's bar on new adds beginning on March 11, 2005, does not trigger the parties' "change of law" obligations under current interconnection agreements because it is self-effectuating. Moreover, the implementation of the TRRO is not covered by the Abeyance Agreement. The language of the Abeyance Agreement and the timing of the parties' agreement to hold the change of law process in abeyance both demonstrate that the scope of the agreement was limited only to changes resulting from *USTA II.* It is not reasonable to believe that eight months before the release of the TRRO, BellSouth voluntarily waived its right to amend its existing interconnection agreements with the Joint Petitioners for the TRRO or any other FCC

[1] Under the *Mobile-Sierra,* doctrine the FCC may modify the terms of a private contract if the modification will serve the public interest.

Order that could be tangentially related to *USTA II*. BellSouth also noted that the deadline to add new issues under the Abeyance Agreement expired on October 2004. This means that, while parties could add issues arising out of *USTA II*, they could not add issues arising out of the TRRO because it had not been issued. As for the phrase in the Abeyance Agreement, "*USTA II* and its progeny," the term "progeny" cannot refer to the TRRO because "progeny" means a line of opinions that succeed a leading case and could therefore only refer to opinions of a court or a state commission reaffirming or restating the D.C. Circuit's decision in *USTA II*.

Public Staff identified the major issue as being whether the FCC intended for an ILEC to be able to refuse to provide new UNE-P adds as of March 11, 2005, or whether it intended for such provision to cease after the ILEC and the interconnecting CLP had arrived at a new agreement through the change of law provisions of their existing interconnection agreement. The Public Staff believes that the FCC did intend that ILECs no longer be compelled to provide new adds after March 11, 2005. This is based upon a reading of the TRRO as a whole. The TRRO states some fifteen times that there will be no new adds. While the TRRO does refer to the change of law process in Paragraph 227, the reference comes immediately after discussion of the transition process for the embedded base of UNE-P customers. At the oral argument, the CLPs placed much reliance on their reading of the *Mobile-Sierra* doctrine, specifically that the FCC may modify a contract only if it has made particularized findings that the public interest demands such modification. The CLPs appear to make two alternative arguments: either the failure to meet the standards for application of the doctrine shows that the FCC did not intend to modify interconnection agreements to disallow new adds until the conclusion of any change of law negotiation or, if the FCC did intend to modify the contracts, it did so improperly by failing to make particularized findings that the public interest demanded the abrogation of interconnection agreements. While it is not clear why the FCC did not address the application of the *Mobile-Sierra* doctrine, this omission is not persuasive evidence that the FCC intended anything other than to eliminate the requirement to provide new UNE-P adds. The proposition that the Commission should reject the FCC's attempt to abrogate private interconnection agreements because it failed to comply with the *Mobile-Sierra* doctrine should also be rejected. The role of the Commission is generally not to determine whether an FCC Order complies with the law but rather to interpret and apply FCC Orders as best it can. Federal courts are in a much better position to determine if the FCC exceeded its authority or complied with all applicable law than the Commission. Finally, the Public Staff argued that it would be illogical for the FCC to prescribe a 12 month period to perform tasks for an orderly transition and at the same time require BellSouth to provide new UNE-P arrangements until the end of the 12 months or the conclusion of the change of law process, whichever comes sooner. This would undermine the orderly transition process prescribed by the FCC. Also, CLPs are not left without alternatives to new UNE-P adds, since they can negotiate commercial agreements or serve the customer through resale or UNE-L.

US LEC argued that the interconnection agreements between BellSouth and the CLPs are valid and enforceable and have not been changed in a self-effectuating manner by the TRRO. Rather, it is contemplated both in the interconnection agreements and in the TRRO that the change-of-law process will be observed, including in the matter of new adds.

US LEC maintained that the Commission has the authority to rule on matters pertaining to the enforcement of interconnection agreements. It observed that the FCC does not set the terms of interconnection agreements, but rather such agreements are the product of negotiations between the parties and, in some cases, arbitration by state commissions. These agreements are neither filed nor approved by the FCC and the FCC plays no role in their enforcement. The principal connection of the agreements with the FCC is that the FCC's rules provide the backdrop for the parties' negotiations and the decisions of state commissions. Parties can negotiate and agree to terms that deviate from the rules established by the FCC. Thus, it does not follow that any changes to the FCC's rules of interconnection automatically and by operation of law override contrary provisions of negotiated and approved interconnection agreements. Specifically, the change-of-law provisions in BellSouth's interconnection agreements have not been abrogated by the TRRO. The FCC has stated plainly that the *Mobile-Sierra* doctrine does not apply to interconnection agreements. *See In the Matter of IDB Mobile Communications, Inc. v. Comsat Corp.*, FCC 01-173 (released May 24, 2001) (*IDB Mobile*). US LEC also noted that the FCC had specifically refused to overrule provisions of interconnection agreements in the TRO. The *Mobile-Sierra* doctrine is not mentioned anywhere in the TRRO, nor are there any words in the TRRO definitively stating as such an intent to override change-of-law provisions. BellSouth's various citations to that effect in the TRRO are inapposite and fall far short of a clear statement. In any event, the *Sierra-Mobile* doctrine is not applicable to state-approved agreements. Even if it were, it would require factual findings not present in the TRRO to support explicit findings of the public interest determination.

US LEC further maintained that BellSouth's position as to loop and transport provisioning is inconsistent with the express provisions of the TRRO. This, too, BellSouth wishes to deny as to new adds. The TRRO sets up a self-certification procedure by CLPs, which the ILECs must accept but could challenge through dispute resolution procedures. US LEC did note that BellSouth had backed off this position at the oral argument, where it stated that it would follow the procedures set forth by the TRRO with respect to high capacity loops and dedicated transport.

US LEC pointed out that, if BellSouth's views are countenanced, there would be controversy over the meaning of "embedded customer." The TRRO text speaks repeatedly of the "embedded customer," while the new rule adopted in the TRRO speaks in terms of embedded lines and loops. It is unknown at this point what interpretation BellSouth will take with respect to this question. Perhaps BellSouth will tell CLPs that they can no longer serve an "embedded customer" because they seek a change to an embedded line or because they seek a new line. These are the types of disruptions that the change-in-law negotiations are intended to prevent.

Joint Petitioners rejected BellSouth view that aspects of the TRRO are self-effectuating. To the contrary, any change in law must be incorporated into interconnection agreements before becoming effective. The TRRO has expressed no clear intent that existing interconnection agreements should be abrogated, and the legal doctrine on which BellSouth relies does not apply to interconnection agreements. Even if it did, the TRRO does not contain the analysis required to invoke the doctrine.

With respect to the "self-effectuating language" in Para. 3, Joint Petitioners noted that this was the single use of this term in the TRRO. It means nothing more than that the FCC adopted an impairment test that did not require delegation to the states for specific impairment findings. The test itself is self-effectuating. The importance attached by BellSouth to the March 11, 2005, "effective date" is also misplaced. All FCC rules have an effective date, but this does not mean that they are automatically incorporated into interconnection agreements as of this date.

Joint Petitioners maintained that the *Mobile-Sierra* doctrine does not apply to interconnection agreements under Section 252. *See, IDB Mobile.* The doctrine only applies to contracts *filed* with the FCC and does not extend to contracts that are construed to be subject to the FCC's jurisdiction. *See, Cable and Wireless.* In any event, the TRRO contains none of the analysis required under *Mobile-Sierra.*

Joint Petitioners also responded to the rhetorical question at oral argument as to what public interest would be served by permitting new adds by pointing to the sanctity of contracts. The question is not whether the Commission has authority under North Carolina law to invalidate certain anticompetitive contracts but whether the integrity of contracts can be violated by the FCC absent proper application of the *Mobile-Sierra* doctrine. The *Callery Properties* case, which BellSouth cited for the proposition that an agency "can undo what is wrongfully done by virtue of its order," is not apposite. It pertained to the Federal Power Commission and concerned the making of refunds. It does not suggest that the FCC may abrogate privately negotiated contractual provisions with no reflection in the record of its intent to do so or that such action is in the public interest.

Significantly, the FCC refused to override the negotiation process in the TRO, and indeed the language of the TRRO obligates BellSouth to negotiate (Para. 233). The language relied upon by BellSouth simply says that the transition period does not allow new adds, but the FCC did not prohibit new adds under existing interconnection agreements. The TRRO does not preclude new adds before a transition plan is adopted, but it clearly contemplates that a transition plan will be incorporated into existing interconnection agreements for delisted UNEs. The TRRO does expressly state that the parties are free to negotiate alternatives to the transition plan included in the Order. *See,* Para. 145. Fundamental fairness requires BellSouth to follow the Section 252 process.

Finally, the Joint Petitioners argued that BellSouth's refusal to process new adds is contrary to the Abeyance Agreement. The Joint Petitioners, among other arguments, placed particular stress on the provision that the parties "have agreed to avoid a separate/second process of negotiating/arbitrating change-of-law amendments to the current interconnection agreements to address *USTA and it progeny.* (Abeyance Agreement at 2, emphasis added). BellSouth's reading of the term "progeny" is too narrow. It is not limited to court or state commission decisions but has the wider meaning of "offspring." Surely, the TRRO is the "offspring" of *USTA II.* Moreover, the parties had anticipated this contingency because of the reference in the Joint Issues Matrix submitted in October 2004 concerning "Final Rules," defined as "an effective order of the FCC adopted pursuant to the Notice of Proposed rulemaking [NPRM], WC Docket No. 04-313, released August 20, 2004, and effective September 13, 2004." The NPRM referenced in this definition is the *Interim Rules Order.* The "Final Rules" referenced in the revised matrix cannot refer to anything other than the TRRO, which is the order promulgating "Final Rules."

Lastly, the Joint Petitioners argued that the weight of authority from other jurisdictions favors Joint Petitioners' position. This is especially so in the BellSouth region.

MCI echoed many of the arguments made by the other CLPs. MCI particularly stressed that the FCC had nowhere expressed an intent to abrogate existing contracts and, even if it had, it had nowhere discussed or met the high standards for abrogation under the *Sierra-Mobile* doctrine. BellSouth appears to argue that the FCC's intent to abrogate was implied, but this runs afoul of the relevant standards that must be met. Notably, the Georgia District Court Order did not discuss the *Mobile-Sierra* doctrine. BellSouth's citation to the public interest involved in the demise of UNE-P—that it does not promote investment—is insufficient to justify sidelining the interconnection agreement change-of-law process. There are serious questions as to whether the FCC has the authority to abrogate interconnection agreements (*IDB Mobile),* or whether it can abrogate contracts over which it lacks exclusive authority (*Cable & Wireless). Callery Properties* is inapposite because it was not the unbundling conclusions *per se* that were found to be wrongful, but rather there was no longer impairment because of changed circumstances. Indeed, the principal "wrong" found by the court in *USTA II* was the FCC's sub-delegation scheme. Thus, the TRRO cannot be said to be "undoing" anything "wrongfully done." MCI also stated that there had been numerous decisions, especially in the BellSouth region, that have favored the CLPs. MCI also argued in its Motion that it should be entitled to UNE-P under Section 271.

CTC made a supplemental filing setting out various issues that there were to negotiate when the TRRO clearly eliminated certain UNEs. Such issues include combining multiple DS1 circuits to DS3 circuits, revising EEL conversion language, combining resale and UNE service on the same account, developing shared collocation arrangements, combining special access and UNE services, implementing a methodology for resolving disputes regarding UNE obligations, and working out connections to shared transport.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

1. New Adds

After careful consideration of the arguments and filings of all parties, the language of the TRRO, the decisions of other state commissions, and the practical implications of this decision, the Commission concludes that good cause exists to decline to declare that BellSouth must provide "new adds" of UNE-P, DS1, and DS3 UNEs outside of the embedded customer base after March 11, 2005, but that BellSouth should continue to process orders for the existing base of CLP customers pending completion of the transition process.

The principal question before the Commission is whether the FCC intended for an ILEC to be able to refuse to provide new UNE-P, DS1, and DS3 adds as of March 11, 2005, or whether it intended such provision to cease only after the ILEC and the interconnecting CLP had arrived at new contractual language through the change of law provisions of the interconnection agreement.

As has been remarked by others, the TRRO is not in all respect a model of clarity. That is why there is a disagreement on the question of "new adds." However, one thing is clear about the TRRO. It is the culmination of a long and tortuous process in which the FCC has examined unbundling and has frequently made decisions concerning this subject that have repeatedly been found wanting by the federal courts, most recently by the D.C. Circuit in *USTA II*. The TRRO was the FCC's attempt to conform itself to the demands of that decision. In doing so, it de-listed certain UNEs and crafted a transition period for the embedded customer base for the purpose of providing an orderly transition to other arrangements.

The Commission is persuaded that the sounder reading of the TRRO is that the FCC intended that "new adds" outside the embedded customer base should go away immediately—i.e., as of March 11, 2005—for the reasons as generally set forth by BellSouth and the Public Staff. The alternative reading is too strained and involves the creation of various anomalies and even absurdities. For example, if "new adds" outside of the embedded customer base were allowed, how does this assist in an orderly transition *away* from such arrangements, which, however obscure the FCC may have been in other matters, was its plain intent here? How sensible is it to have the question of "new adds" outside the embedded customer base to be the subject of negotiations in the transition period when that question has already been decided in the TRRO?

At the oral argument and in their filings, the CLPs argued that the FCC did not meet the requirements of the *Mobile-Sierra* doctrine said to be necessary for the FCC to abrogate contract provisions. Broadly speaking, this doctrine states that the FCC may modify the terms of private contracts if the modification serves the public interest. Essentially, the CLPs maintained that the FCC's intent to abrogate was less than plain and its public interest finding was not expressed with sufficient particularity.

The Commission is not convinced that the *Mobile-Sierra* doctrine is the only avenue by which the FCC can abrogate contract provisions. For example, an agency may abrogate a contract provision when it is undoing "what is wrongfully done by virtue of a previous order." *Callery Properties*, cited with approval in the *Georgia District Court Order*. The context here is important, since in *USTA II*, the D.C. Circuit made harsh observations about the FCC's "failure, after eight years, to develop lawful unbundling rules."

But even if *Mobile-Sierra* is the appropriate approach to contract modification, the Commission believes that the FCC has expressed its belief as to the overriding public interest with sufficient particularity given the general nature of the subject-matter, which is the broader subject of the availability of certain classes of UNEs. The public interest the FCC expressed is related to the investment in infrastructure and the efficient allocation of resources in the economy.

In any event, the contracts that are being modified are not strictly private in nature but are rather contracts which, if negotiated, are approved by government, and, if not negotiated, are arbitrated by government. The entire process, from start to finish, is implicated in a regulatory process which, while formally conducted by state commissions (or by the FCC in default of state action), must examine in the first instance FCC orders and rules. *Accord., E.spire Communications, Inc. v. N.M. Pub. Regulation Comm.*, 392 F.3d. 1204 (10th Cir., 2004); *Verizon Md., Inc. v. Global Naps, Inc.*, 377 F.3d. 356 (4th Cir., 2004) (interconnection agreements are a "creation of federal law" and are the "vehicles chosen by Congress to implement the duties imposed by Sec. 251"). It is therefore entirely reasonable that the FCC can abrogate contract provisions found not to be in the public interest given the underlying legal structure.

Finally, there is the question of how far the ban on "new adds" should extend as applied to the embedded customer base. The Commission believes the better view is that ILECs like BellSouth should continue to process orders for the existing base of CLP customers pending completion of the transition process. Although this decision, like many others, is likely to be controverted, and colorable arguments can be adduced on either side, the Commission believes that the bright line that the FCC was drawing was between those *inside* the embedded customer base and those *outside* of it. After all, the TRRO focuses on the "embedded customer base," not on existing access lines. The Commission does not believe that it was the FCC's intent to impede or otherwise disrupt the ability of CLPs to adequately serve their existing base of customers in the near term. The Commission notes that the CLPs now serve thousands of customers, many of them business customers, with these de-listed UNE arrangements. Given the vital importance of fast telecommunications access in a highly dynamic economy, these customers would be baffled and impatient if they were to discover that adding a new line or even simply a new feature in the near term was impossible with their current provider. They may very well lose confidence in that provider. This is not good for competition, which is the overarching purpose of the Telecommunications Act.

Thus, we believe that, through a planned, orderly, and nondisruptive transition process under state commission supervision, the FCC intended that the CLPs should retain the ability to adequately serve their customers during the transition period. The Commission has already established a docket with respect to BellSouth in Docket No. P-55, Sub 1549 to deal with the transition.

2. Abeyance Agreement

The same analysis applicable to "new adds" also applies to the Abeyance Agreement between BellSouth and the Joint Petitioners. Under the Agreement's terms, the existing, underlying interconnection agreement is to be carried forward until the new interconnection agreement is reached. Although the Joint Petitioners have the better of the argument that the phrase "*USTA II* and its progeny" includes the TRRO, this is not determinative. What is determinative is that the FCC reached out and negated certain existing provisions of all interconnection agreements to the extent that they allow "new adds" outside of the embedded customer base. This applies *pari passu* to the existing agreement between BellSouth and the Joint Petitioners.

3. Loop and Transport

BellSouth indicated at oral argument that it would continue to provision loop and transport in accordance with the self-certification/protest process outlined in the TRRO. BellSouth's announcement renders this issue moot.

4. State Law UNEs

In this docket there has been some discussion as to whether or not delisted UNEs could nevertheless be revived under state law. This is an interesting discussion, but this discussion is ultimately irrelevant to the issue before the Commission in this docket. Although G.S. 62-110(f1) allows the Commission to order the "reasonable unbundling of essential facilities, where technically and economically feasible," the Commission has not made the findings necessary to require the provision of delisted UNEs under state law.

5. Section 271 UNE-P

MCI argued that Section 271 independently supported its right to obtain UNE-P from BellSouth. BellSouth denied this, saying that while it is obligated to provide unbundled local switching under Section 271, such switching is not required to be combined with a loop, is subject to the exclusive jurisdiction of the FCC, and is not provided via interconnection agreements. The Commission does not believe that there is an independent warrant under Section 271 for BellSouth to continue to provide UNE-P.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

dl041805.01

DOCKET NO. P-7, SUB 825
DOCKET NO. P-10, SUB 479

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Carolina Telephone and Telegraph Company and Central Telephone Company for Approval of Price Regulation Plans Pursuant to G.S. 62-133.5	)	ORDER APPROVING MODIFICATION OF SPRINT PRICE PLANS

HEARD: Monday, January 3, 2005, in the District Court Building, Courtroom B, 111 Main Avenue, N.E., Hickory, North Carolina; Tuesday, January 4, 2005, in the Randolph County Courthouse, 4th Floor, Courtroom 4B, 176 E. Salisbury Street, Asheboro, North Carolina; Monday, February 7, 2005, in the Sheppard Memorial Library, Meeting Room A, 530 Evans Street, Greenville, North Carolina; Tuesday, February 8, 2005, in the Cumberland County Courthouse, Commissioner's Meeting Room, 117 Dick Street, Fayetteville, North Carolina; Tuesday, March 15, 2005, in the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina; and Wednesday, March 16, 2005, in the Commission Hearing Room, Dobbs Building, Raleigh, North Carolina.

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

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BY THE COMMISSION: G.S. 62-133.5(a) provides that "[a]ny local exchange company [LEC], subject to the provisions of G.S. 62-110(f1), that is subject to rate of return regulation pursuant to G.S. 62-133 . . . may elect to have the rates, terms and conditions of its services determined pursuant to a form of price regulation, rather than rate of return or other form of earnings regulation." 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."

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 also 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.

Carolina Telephone and Telegraph Company ("Carolina") and Central Telephone Company ("Central") (collectively referenced herein as "Sprint") are currently operating pursuant to the price regulation plan which was the subject of the Commission's Order Authorizing Price Regulation issued in these dockets on May 2, 1996 (the "Original Plan"), as subsequently amended. G.S. 62-133.5(c) provides that a LEC subject to price regulation under G.S. 62-133.5(a) "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. "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 August 19, 2004, Sprint filed with the Commission its 2004 Revisions to Sprint's Price Regulation Plan (the "August 2004 Revised Plan"), and the Commission issued its Order Setting Hearing on September 1, 2004. In the August 19, 2004 Sprint filing, Sprint advised the Commission that major substantive changes to the Original Plan reflected in the August 2004 Revised Plan included: (a) reduction in the number of service categories made in consideration of the increasingly competitive telecommunications environment in North Carolina; (b) revision of the limits on the aggregate increase for the price of services in the Basic Services category to the rate of inflation, with this category to include, among others, basic residential and single-line business local exchange services; (c) transfer of all service bundles and service packages to the Full Pricing Flexibility Services category; and (d) updates to the plan to make it compliant and consistent with changes to the applicable North Carolina statutes. The Commission's September 1, 2004 Order Setting Hearing scheduled a hearing on the August 2004 Revised Plan for February 8, 2005, and required the Public Staff and Sprint to confer with respect to the text of appropriate public notices to be accomplished by bill insert and newspaper publication. On September 29, 2004, the Commission issued its Order Regulating Discovery and Approving Modified Protective Agreement establishing discovery procedures.

On October 12, 2004, the Commission issued its Order Scheduling Public Hearings and Requiring Public Notice, pursuant to which public hearings were scheduled to be held in Hickory, Asheboro, Greenville, Fayetteville, and Raleigh.

Over the months that followed, various motions were filed requesting extensions of time and rescheduling of hearing dates, and appropriate orders were issued extending time as appropriate and rescheduling hearing dates. There have been a number of other orders regulating discovery and otherwise administering the hearing process. On November 1, 2004, Sprint filed the direct testimony of Brian K. Staihr, Senior Regulatory Economist, and Linda K. Gardner, Director, State Regulatory. On February 4, 2005, MCImetro Access Transmission Services, LLC and MCI WorldCom Communications, Inc. (collectively, "MCI") filed the direct testimony of Greg Darnell, Senior Manager – Regulatory Economics. On January 21, 2005, the United States Department of Defense and other federal executive agencies filed the testimony of Harry Gildea, a consultant with Snavely King Majoros O'Connor & Lee, Inc. On February 4, 2004, the Public Staff filed the testimony of Ben Johnson, Ph.D., a consulting economist and President of Ben Johnson Associates, Inc.

Public notice in the form approved by the Commission was mailed to each Sprint customer as ordered by the Commission and was published in seventy-eight newspapers within the State of North Carolina, with publication in each newspaper being made at least twice as evidenced by the Affidavit of Publication filed by Sprint with the Commission on March 15, 2005.

On October 26, 2004, in Docket No. P-100, Sub 133, RTI International submitted to the Commission a Survey of Local Telecommunications Competition in North Carolina (the "RTI Report"). In its Order Regarding RTI Report issued on November 10, 2004, the Commission directed that the RTI Report be admitted in evidence in this case. The RTI Report provides an analysis of the state of competing local provider ("CLP") and incumbent local exchange carrier ("ILEC") competition in telecommunications services in the State of North Carolina, including Sprint's service areas.

On February 11, 2005, Sprint filed notice with the Commission that Sprint and the Public Staff had entered into a Stipulation and Agreement Between Sprint and Public Staff and attached to the notice a copy of the price regulation plan stipulated to by Sprint and the Public Staff (the "Stipulated Plan"). In this filing, Sprint and the Public Staff expressed the hope that, if the Commission believed it necessary to permit the filing of additional testimony to address the Stipulated Plan, the Commission would modify the procedural schedule in these dockets to permit the filing of such testimony on or before March 8, 2005, that the testimony previously filed could be stipulated into evidence, and that the March 29, 2005 hearing could be canceled.

On February 16, 2005, the Commission issued its Order Requesting Comments Regarding Procedure seeking comments from all parties in these dockets regarding Sprint's request for modification of the procedural schedule. Responses thereto were filed by the Carolina Utility Customers Association, Inc. ("CUCA") and MCI. CUCA objected to the procedural recommendations advanced by Sprint and the Public Staff and asserted the right to cross-examine any witnesses presenting testimony in support of the Stipulated Plan. MCI objected to the procedural recommendations advanced by Sprint and the Public Staff unless the parties to the proceeding were provided an opportunity to submit testimony regarding the Stipulated Plan and unless the existing hearing date was preserved or a later hearing date acceptable to all parties was adopted.

On February 28, 2005, the Commission issued its Order Scheduling Stipulated Plan for Hearing setting the Stipulated Plan for expedited evidentiary hearing on March 16, 2005. That Order provided that testimony previously prefiled by witnesses for all of the parties would be entered in the record as evidence, and that, unless a party made a filing not later than Thursday, March 10, requesting an opportunity to cross-examine a particular witness or witnesses, it would not be necessary for those witnesses to appear and testify at the hearing. In addition, the Order provided that Sprint and/or the Public Staff should file additional testimony in support of the Stipulated Plan on or before March 8, 2005, and that other parties might also file additional testimony regarding the Stipulated Plan not later than that date. Subsequently, the testimony of Marcus Potter, Regulatory Affairs Manager for North Carolina, on behalf of Sprint, and of Charles B. Moye, Engineer with the Public Staff's Communications Division, on behalf of the Public Staff, was filed on March 8, 2005. On March 9, 2005, CUCA gave notice that the attendance of witnesses Staihr and Gardner would also be required. No other party requested the appearance of any other witnesses. On March 10, 2005, the Commission entered an Order announcing that the parties would be afforded an opportunity, pursuant to G.S. 62-78(a), to make oral arguments on relevant issues at the close of the March 16, 2005 hearing and requesting the parties to file briefs and/or proposed orders on or before March 18, 2005. On March 11, 2005, Sprint gave notice that witness Potter would adopt witness Gardner's testimony as his own.

At the January 3, 2005 public hearing in Hickory, three public witnesses offered statements in support of revisions to Sprint's Price Regulation Plan. No public witnesses appeared in opposition to such revisions. At the January 4, 2005 hearing in Asheboro, three public witnesses also offered statements in Sprint's support, and no public witnesses appeared in opposition to the relief sought by Sprint. At the February 7, 2005 public hearing in Greenville, four public witnesses offered statements in Sprint's support. Two Sprint customers appeared as public witnesses to express opposition to increases in their telephone charges. At the February 8, 2005 public hearing in Fayetteville, two public witnesses offered statements in Sprint's support, and no public witnesses appeared in opposition. No public witnesses appeared at the March 15, 2005 public hearing in Raleigh.

At the beginning of the March 16, 2005 evidentiary hearing in Raleigh, CUCA made an objection to the procedure announced by the Commission in its March 10, 2005 Order. The Attorney General also expressed concern about the deadline for filing briefs and/or proposed orders. The exceptions of CUCA and the Attorney General were noted for the record. Sprint offered the testimony of witnesses Staihr and Potter. Witness Potter adopted the prefiled testimony of Sprint witness Gardner. Witness Moye appeared and testified on behalf of the Public Staff.

On March 18, 2005, Sprint and the Public Staff filed a Joint Proposed Order, and the Attorney General, CUCA and Pay Tel Communications Inc. ("Pay Tel") filed Post-Hearing Briefs. Both the Attorney General and CUCA asked the Commission not to approve the Stipulated Plan. Pay Tel did not oppose the Stipulated Plan, but raised concerns specific to the payphone industry that it wanted the Commission to consider.

Based on the foregoing, the evidence adduced at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. The applicants are "local exchange companies" as that term is defined in G.S. 62-3(16a). Sprint is subject to the provisions of G.S. 62-110(f1). Sprint 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 Sprint 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.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 1

Finding of Fact and Conclusion of Law No. 1 is supported by the record as a whole and is not contested.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 2 - AFFORDABILITY

Finding of Fact and Conclusion of Law No. 2 (and Nos. 3-5 as well) are supported by the testimony and exhibits of Sprint witnesses Staihr, Gardner, and Potter and Public Staff witnesses Johnson and Moye, together with the RTI Report. The Commission has also taken into consideration the testimony of MCI witness Darnell and Department of Defense witness Gildea, although these witnesses did not specifically address the Stipulated Plan.

Witness Staihr testified as to the economic rationale supporting the need to revise Sprint's Original Plan; the economic context in which revisions to the Original Plan should be evaluated; the recent changes in the competitive landscape for telecommunications services in North Carolina; the effects of those changes on the proper role of regulation with respect to the pricing of services; and the reasons Sprint believes there is no longer a need for an explicit productivity offset in its price regulation plan. Witness Gardner, whose testimony was adopted at the hearing by witness Potter, testified as to the specific provisions of the August 2004 Revised Plan and the reasons for the changes that had been made from the Original Plan. Witness Johnson presented a critique of the August 2004 Revised Plan, asserting that this plan would allow Sprint an excessive degree of pricing flexibility because effective competition does not yet exist with respect to certain services and in certain geographical areas in Sprint's service area.

Witness Potter discussed the detailed provisions of the Stipulated Plan, explained that it is consistent with the requirements of G.S. 62-133.5(a) and (c), and stated that it represents a fair compromise between Sprint's initial position in this case and that of the Public Staff. He further provided evidence that Sprint experienced a net loss of access lines to competition beginning in 2000, that Sprint continues to have a net loss of access lines to date, and that there is virtually no prospect of a reversal of this trend. When considered with the testimony of witness Staihr, who testified to significant risk for traditional wireline local telephone companies from wireless and voice over internet protocol ("VoIP") providers, the record establishes that generally for services in Sprint's service areas, price constraints imposed by the existence of competitors are current, real, and effective, aiding our determination that the Stipulated Plan will result in affordable rates. Witness Moye testified as to the differences between the Stipulated Plan and the Original Plan, and he expressed the opinion that the Stipulated Plan meets the criteria of G.S. 62-133.5(a) and (c). Like witness Potter, he indicated that the Stipulated Plan is a reasonable compromise between the initial positions of Sprint and the Public Staff.

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 both the Original Plan and the Stipulated Plan, this service is included in the Basic Services category. However, the Stipulated Plan allows Sprint greater flexibility to adjust the price of basic local exchange service than the Original Plan. Under the Original Plan, aggregate annual price changes for Basic Services were limited to the rate of inflation as measured by the annual change in the Gross Domestic Product Price Index ("GDPPI") minus a productivity offset of 2%; in the Stipulated Plan the offset is reduced to zero. As witness Staihr noted, a productivity offset was justifiable when telephone companies were experiencing increases in access lines and benefiting from economies of scale. However, in view of the significant reversal and net loss of access lines, an offset is no longer warranted. Under the Original Plan, the maximum annual price increase for any rate element in the Basic Services Category was equal to the change in GDPPI plus 3%; under the Stipulated Plan, individual rate elements in this category can be increased by up to 12% per year. The Stipulated Plan also includes a minimum increase provision, under which any rate element in the Basic Services category may be increased by $0.35 annually if it is priced on a flat-rated monthly basis, $0.15 annually if it is priced on a per-use basis, or $0.01 annually if it is priced on a per minute of use basis, even if this increase exceeds 12%.

The Commission concludes that, even with this additional pricing flexibility, the Stipulated Plan protects the affordability of basic local exchange service. Prices for Basic Services in the aggregate can only increase commensurate with a change in prices for other goods and services in the general economy. Aggregate price increases for rate elements which are above the rate of inflation must be accompanied by commensurate (offsetting) price reductions for other rate elements in order to be compliant with the Stipulated Plan's aggregate pricing restrictions. The Stipulated Plan further protects the affordability of basic local exchange services by limiting the potential annual price increase generally for any single rate element to 12%.

Furthermore, the record shows that with respect to basic local exchange service, Sprint's local exchange companies face wireline competitors in 90% of their exchanges and wireless competitors in virtually every exchange.[1] In contrast, when the Original Plan was adopted in 1996, there was little or no competition for basic service. The limited increase in pricing flexibility allowed under the Stipulated Plan for basic local exchange service is justified by the increased competition that exists for basic local exchange service in Sprint's North Carolina telecommunications markets.

DISCUSSION OF 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 differences between the provisions on service quality and service penalties in the Stipulated Plan and in the Original Plan are minimal. Under the Stipulated Plan, the Commission retains powers and authority with regard to the provision of quality service. Sprint will continue to operate under Commission Rule R9-8 and will be subject to the service penalties set forth in the

[1] Because of the lack of responses, the RTI Report discloses little about the status of competition between wireline and wireless providers or VoIP providers.

Stipulated Plan. Furthermore, the Commission will retain oversight for service quality, complaint resolution, and compliance with all elements of the Stipulated Plan and applicable state law.

Thus, the Commission concludes the Stipulated Plan reasonably assures the continuation of basic local exchange service that meets the reasonable service standards set forth in Commission Rule R9-8.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW
NO. 4 - NO PREJUDICE AMONG CUSTOMER CLASSES

CUCA contended through cross-examination, during oral argument, and in its brief that the Stipulated Plan unreasonably prejudices business customers and is inconsistent with the public interest. CUCA argued that Sprint's residential rates are priced below cost, while business rates are generally priced above cost and serve to subsidize residential customers. According to CUCA, it is illogical to allow Sprint increased pricing flexibility to raise business rates. In particular, CUCA pointed out that intrastate switched access charges are substantially above cost and need to be reduced. CUCA asserted that, instead of approving the Stipulated Plan, the Commission should require Sprint to establish a fourth "basket" in its current Price Regulation Plan that would contain only residential basic local exchange services and intrastate switched access services. CUCA further recommended that the Commission mandate reductions in switched access service rates over a certain period of time until they reach their economic cost and provide Sprint the discretion to increase its residential basic local service rates by an offsetting amount.

The Commission does not find CUCA's argument persuasive. Neither CUCA nor any other party presented a witness in support of CUCA's proposal. Furthermore, as witness Potter testified, while it may seem counterintuitive that competition could result in higher rates for certain services rather than lower rates, this is in fact the case when rates for services priced below cost are increased so that rates for services priced above cost can be reduced. Allowing increased pricing flexibility for business services reflects the appropriateness of placing greater reliance on market forces to control the prices for such services. CUCA's proposal is further flawed in that access charges are not the only charges that need to be reduced, and it is simplistic to think that necessary changes in rates for residential services can be appropriately offset or balanced by changes in access charges alone. Business customers currently pay access charges as well. Doing as CUCA recommends would be contrary to the statutory mandates that the plan protect the affordability of basic local exchange service and that the plan not unreasonably prejudice any class of telephone customers because CUCA's proposal would require residential subscribers of basic local exchange service to absorb all of the costs of access charge reductions.

Under the Stipulated Plan, switched access charges are already subject to greater restrictions than other charges. They are included in the Basic Services category, and under section 6(B)(3) of the Plan, they may not at any time be increased above their present level. Section 6(A)(4) provides an incentive to reduce switched access rates, as it provides that the "headroom" resulting from reductions in these charges (up to a maximum of $3,000,000 for Carolina and $650,000 for Central) may be "transferred" from the Basic Services category to the High Pricing Flexibility Services category to recover revenue reductions associated with switched access rate reductions. To the extent that above-cost switched access charges make it difficult for Sprint to compete for business customers, Sprint will have an additional incentive to reduce these charges, or to enter into Contract Service Arrangements with business customers, as it is authorized to do under G.S. 62-133.5(f). However, mandating that all increases in rates for basic residential services be automatically offset by corresponding reductions in switched access charges, as CUCA proposed, would limit Sprint's ability to manage its response to changes in the marketplace. In the Commission's judgment, such a requirement would be inappropriate and unreasonable in an era of increased competition in Sprint's North Carolina service territories and would be inconsistent with the increased pricing flexibility that the Stipulated Plan is intended to provide.

As for CUCA's assertion that residential rates are too low, the Stipulated Plan allows Sprint to increase these rates by 12% per year, subject to the restriction that aggregate increases in the Basic Services category may not exceed the annual increase in GDPPI. Allowing this degree of rate rebalancing is consistent with the public interest. Increases in residential rates significantly larger than this may jeopardize the affordability of basic local exchange service, which must be protected under G.S. 62-133.5(a) and (c). If residential rates were suddenly increased to a fully cost-based level in certain high-cost areas, the resulting rate shock could endanger the State's economy and would certainly be unacceptable to customers.

Witness Potter testified that the Stipulated Plan will provide Sprint with the ability to rebalance rates over a reasonable period of time, i.e., three to four years, which is apparently acceptable to Sprint. As noted above, the Commission considers the rate movements allowed in this manner under the Stipulated Plan to be consistent with the public interest. Allowing a more rapid increase in basic rates would raise concerns as to affordability and reasonableness.

Both CUCA and the Attorney General questioned the 12% rate element constraint for Basic Services and the 20% rate element constraint for the High Pricing Flexibility Services Category under the Stipulated Plan. Witness Potter explained that, if the price of a rate element increased by 20%, there would be a corresponding decrease in prices for other rate elements in order to stay within the aggregate pricing limit for that category. He further explained that the flexibility to raise prices for rate elements by 20% does not mean that such increases will be tolerated by the marketplace. The Commission notes that the rate element constraint for the comparable category, Non-Basic 1, in the Original Plan is the change in GDPPI plus 15%, which could be expected to allow rate element increases of at least 18%. In the Commission's view, raising the constraint from 18% to 20% will give Sprint only slightly greater pricing flexibility than it currently has for services in this category and will not unreasonably prejudice any class of customers. Finally, as witness Potter testified, business customers often negotiate with Sprint to secure service at below tariff rates and will continue to do so under the Stipulated Plan. For these reasons, the Commission believes that concerns about the 20% rate element constraint for High Pricing Flexibility Services are not well-founded. Similarly, the challenge to the 12% rate element constraint for Basic Services is not well-founded due to the impact of the category constraint applicable to Basic Services and the existence of competitive forces. Thus, both rate element constraints appropriately balance the need to protect customers from rate shock with the movement to an economically efficient rate structure that will eventually result from the development of a competitive local telephone industry.

The provisions of the Original Plan were found to satisfy the statutory requirement that the plan not unreasonably prejudice any class of telephone customers, including telecommunications companies. Although telecommunications companies intervened in the current proceeding, none appeared at the hearing or opposed the Stipulated Plan. Although MCI filed testimony in this proceeding urging the Commission to take certain actions with respect to switched access charges, it did not appear at the hearing or file a post-hearing brief. In the Commission's opinion, the Stipulated Plan provides Sprint with adequate incentives to move switched access rates to a more cost-based level. The Stipulated Plan gives Sprint more flexibility than it has under the Original Plan to rebalance rates while maintaining affordable basic rates and avoiding rate shock. In the Commission's judgment, the provisions of the Stipulated Plan, as they currently exist, do not unreasonably prejudice business customers, telecommunications companies, or any other class of telecommunications customers.

DISCUSSION OF 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 Commission finds the Stipulated Plan to be in the public interest for several reasons. First, it provides 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 will increase. Second, the Stipulated Plan provides affordable rates and assures that Sprint will continue to provide adequate service to its customers. Third, the service performance measures and penalties contained in the Stipulated Plan should have a major influence upon Sprint's behavior during the operation of the Stipulated Plan. Fourth, the Stipulated Plan properly places the risk of future investment decisions on Sprint's shareholders, which is where the risk must rest in a competitive marketplace, rather than on the ratepayers. Fifth, the Commission believes that a competitive marketplace is not only consistent with the goals established by the legislature, but in addition will engender significant benefits for the citizens of the State through improved services, generally lower prices, and greater technological innovation, and will, therefore, offer significant potential for enhanced economic development.

At the same time, the Commission recognizes that the public interest could be adversely affected if telecommunications services were fully deregulated, or regulated so lightly that the only limitations on prices were those imposed by competition, at a time when competition had not yet progressed to the point where it could discipline prices effectively in every market area in Sprint's North Carolina service territories.

In addressing this concern, the Commission notes that there is a close correlation between the assignment of telecommunications services to pricing categories under the Stipulated Plan and the degree of competition for particular services in Sprint's service area. The assignment of services to categories in the Stipulated Plan was determined by negotiation between Sprint and the Public Staff; however, a review of the RTI Report, as well as the data furnished by Sprint in the discovery process, discloses that with very few exceptions the services assigned to the Full Pricing Flexibility Services category are those as to which the greatest degree of competition exists. In contrast, the services categorized as Basic Services are those for which competition is less vigorous. No party objected to the provisions in the Stipulated Plan placing specific services in specific categories or baskets. The Commission finds it significant that the Public Staff, which is responsible under G.S. 62-15 for protecting the interests of the using and consuming public, has been willing to agree to the Stipulated Plan. In addition, the Commission notes that no party has filed testimony in opposition 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 interest standards, to decide complaints concerning anticompetitive behavior, and to oversee the reclassification and regrouping of services and the financial impacts of governmental actions.

The Attorney General contended in his post-hearing brief that approval of the Stipulated Plan would not be consistent with the public interest because Sprint should not be allowed to increase residential rates annually by 12% for an indefinite period of time, the Original Plan continues to afford Sprint an adequate opportunity to respond to competition, the proposed rate element constraints for Basic Services and High Pricing Flexibility Services are arbitrary, and the Stipulated Plan does not provide the public with any concrete benefits. The Commission has cited numerous public benefits from the Stipulated Plan elsewhere in this Order. As previously indicated, the rate element constraints for Basic and High Pricing Flexibility Services are reasonable and appropriate. Furthermore, given the evidence suggesting that at least some Sprint residential rates should be moved closer to a cost-justified level, the limited amount of rebalancing allowed by the Stipulated Plan is consistent with the public interest. Finally, given changing competitive conditions in Sprint's service territories, adjustments to the Original Plan are clearly appropriate. Thus, the Attorney General's arguments do not warrant rejection of the Stipulated Plan.

Accordingly, while still concerned about the irreversible nature of the stipulated plan, a concern also raised in the Attorney General's Brief, the Commission nevertheless concludes that the changes effected by the Stipulated Plan are sufficiently limited, and that the current level of competition in Sprint's local service area is sufficiently advanced, that these changes are consistent with the public interest given the level of competition in Sprint's service territories. Furthermore, the Commission recognizes that, under the Stipulated Plan, it retains the same regulatory oversight authority as afforded under the Original Plan for any request by Sprint 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, Sprint and the Public Staff have negotiated a Stipulated Plan that meets each of the criteria prescribed by G.S. 62-133.5(c) and therefore the Commission finds that approval of the Stipulated Plan is appropriate. A comparison of the Stipulated Plan, the August 2004 Revised Plan, and the plan proposed by Public Staff witness Johnson reveals the extent of Sprint's and the Public Staff's efforts to reach common ground. While CUCA and the Attorney General may not be entirely satisfied with the result, the Commission finds ample evidentiary support for its approval and independently determines that it should be approved. The record shows that the competitive landscape has changed considerably since the Original Plan was approved. The Commission believes that the additional flexibility afforded by the Stipulated Plan will enable Sprint to compete effectively and continue to provide reasonably affordable basic local exchange service. The Commission's decision to approve the Stipulated Plan is based upon its analysis of competitive conditions in Sprint's service territories, and should not be understood as indicating that a different plan would not be appropriate given the existence of different competitive conditions.

The Commission notes that Pay Tel, a provider of pay telephone services in North Carolina, submitted a post-hearing brief in which it focused on issues important to itself and the payphone industry, but did not oppose approval of the Stipulated Plan or address the broader issues in these dockets. Specifically, Pay Tel urged that the Commission's decision in these dockets be without prejudice to the pending proceeding in Docket No. P-100, Sub 84b concerning appropriate payphone access rates; that Sprint's payphone rates be kept in the most restrictive pricing basket or placed in a separate basket; that the "low price service" provisions of the Stipulated Plan not apply to usage-based payphone services; and that the imputation language in the Original Plan be retained in any modified price plan. The Commission observes that the first two Pay Tel "requests" are met by this Order, i.e., this Order is without prejudice to resolution of the pending matters in Docket No. P-100, Sub 84b with respect to Sprint, and payphone rates are assigned to the most restrictive basket. The Commission declines to grant Pay Tel's requests with respect to the low price service provisions and retaining price imputation requirements, since payphone rates must meet applicable federal standards in addition to the provisions of the Stipulated Plan. As always, the Commission must be mindful of the effect of its actions on the telecommunications landscape as a whole in North Carolina, and for the reasons stated hereinabove in this Order, has decided not to grant all of the relief sought by Pay Tel.

Finally, along with CUCA and the Attorney General, the Commission recognizes that the expedited procedure followed in this case is used infrequently in Commission proceedings. However, it is well within the Commission's discretion, pursuant to G.S. 62-78, to prescribe the time for submitting proposed orders and briefs, allow oral argument in lieu of or in addition to briefs, and to expedite the hearing and decision by the use of daily transcripts and other means. Moreover, as CUCA itself stated, many of the same issues were presented in BellSouth Telecommunications, Inc.'s price regulation plan case, Docket No. P-55, Sub 1013, in which CUCA and the Attorney General also participated. The Stipulated Plan was filed more than a month before the hearing was held. This proceeding has been pending since August 2004 and needs to be resolved. No party has shown any prejudice as a result of the expedited procedures employed in this instance. Therefore, the Commission finds and concludes that the Stipulated Plan should be approved without modification or delay.

IT IS, THEREFORE, ORDERED that the Stipulated Plan be, and the same is hereby, approved for implementation by Sprint effective not later than April 22, 2005, provided that Sprint shall, not later than March 30, 2005, refile the Stipulated Plan bearing an effective date not later than April 22, 2005.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of March, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Tb032205.01

DOCKET NO. P-19, SUB 277

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Verizon South Inc.	)	ORDER APPROVING MODIFIED
For, and Election of, Price Regulation	)	PRICE REGULATION PLAN

HEARD: Monday, January 10, 2005, in the Greater Durham Chamber of Commerce Board Room, 14th Floor, 300 W. Morgan Street, Durham, North Carolina; Tuesday, January 11, 2005, in the Public Works Building, Jefferson Room, 307 E. Jefferson Street, Monroe, North Carolina; Tuesday, January 18, 2005, in the Macon County Courthouse, Courtroom A, 5 W. Main Street, Franklin, North Carolina; Wednesday, January 19, 2005, in the Burnsville Town Hall, 2 Town Square, Burnsville, North Carolina; and Monday, April 18, 2005, in Commission Hearing Room 2115, Dobbs Building, Raleigh, North Carolina.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners J. Richard Conder, Robert V. Owens, Jr., Sam J. Ervin, IV, James Y. Kerr, II, and Howard N. Lee

APPEARANCES:

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BY THE COMMISSION: G.S. 62-133.5(a) provides that "[a]ny local exchange company [LEC], subject to the provisions of G.S. 62-110(f1), that is subject to rate of return regulation pursuant to G.S. 62-133 . . . may elect to have the rates, terms and conditions of its services determined pursuant to a form of price regulation, rather than rate of return or other form of earnings regulation." 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."

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 also 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.

Verizon South Inc. ("Verizon") is currently operating pursuant to the price regulation plan which was the subject of the Commission's Order Authorizing Price Regulation issued in this docket on May 2, 1996, (the "Original Plan") as subsequently amended. G.S. 62-133.5(c) provides that a LEC subject to price regulation under G.S. 62-133.5(a) "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 that, "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 2, 2004, Verizon filed with the Commission 2004 Revisions to Verizon's Price Regulation Plan (the "June 2004 Revised Plan"), and the Commission issued its Order Setting Hearing on June 10, 2004. In the June 2, 2004 filing, Verizon advised the Commission that there were four major substantive changes to the Original Plan. First, the number of service categories was reduced from four to two, called the Limited and the Full Pricing Flexibility categories; second, certain basic local exchange services such as R1, B1 and local calling plans, would be classified as either highly competitive in Zone 1 or competitive in Zone 2; third, pricing constraints would apply only to the Limited Pricing Flexibility category, and there would be a single 7 percent per year category constraint; and fourth, during the first two years of the plan, any increases in basic residential or business rates would be offset on a revenue neutral basis with reductions in intrastate switched access rates. The Commission's June 10, 2004 Order Setting Hearing scheduled a hearing on the June 2004 Revised Plan for January 10, 2005, and required the Public Staff and Verizon to confer with respect to the text of appropriate public notices to be accomplished by bill insert and newspaper publication. On June 18, 2004 the Commission issued an Order Rescheduling Hearing for January 31, 2005.

On August 4, 2004 the Commission issued an Order Concerning Service Standards and Self-Effectuating Penalties and Requiring Prefiled Testimony, with supplemental testimony regarding service penalties to be filed by Verizon on or before September 1, 2004.

On August 5, 2004, Verizon filed the direct testimony of Orville D. Fulp, Director-Regulatory; Carl R. Danner, Ph.D., Director, Wilk & Associates/LECG LLC; Gregory M. Duncan, professor at the University of California, Berkeley; and Evan T. Leo, partner, Kellogg, Huber, Hansen, Todd & Evans. On September 1, 2004, Verizon filed the supplemental testimony of witness Duncan regarding service penalties.

On August 20, 2004, the Commission issued its Order Scheduling Public Hearings and Requiring Public Notice scheduling public hearings in Durham, Monroe, Franklin, Burnsville, and Raleigh. On September 29, 2004, the Commission issued its Order Regulating Discovery, establishing discovery procedures.

Over the months that followed, various motions were filed requesting extensions of time and the rescheduling of hearing dates, and appropriate orders were issued extending time as necessary and rescheduling hearing dates. There have been a number of other orders regulating discovery and otherwise administering the hearing process.

On October 1, 2004, the Public Staff filed the testimony of Ben Johnson, Ph.D., a consulting economist and President of Ben Johnson Associates, Inc. On October 5, 2004, the Competitive Telecommunications Association of the South ("CompSouth") filed the direct testimony of Joseph Gillan, a consulting economist.

On October 14, 2004, the Commission issued an Order Regarding Testimony requesting Verizon to address the level of competition it faced on a service-by-service basis in its rebuttal testimony due on October 28, 2004.

On October 26, 2004, in Docket No. P-100, Sub 133, RTI International ("RTI") submitted to the Commission a Survey of Local Telecommunications Competition in North Carolina (the "RTI Report"). In its Second Order Regarding RTI Report issued on December 2, 2004, the Commission directed that the RTI Report be admitted in evidence in this case. By order dated December 22, 2004, the Commission directed that the discovery responses submitted by RTI in Docket No. P-55, Sub 1013 (Price Regulation Docket for BellSouth Telecommunications, Inc.), be included in the record in this case. The RTI Report provides an analysis of the state of competition in telecommunications services among competing local providers ("CLPs") and incumbent local exchange companies ("ILECs") in the State of North Carolina, including Verizon's service areas.

On October 28, 2004, Verizon filed the rebuttal testimony of witnesses Fulp, Danner, Duncan and Leo. On November 12, 2004, CompSouth filed the Supplemental Direct Testimony of witness Gillan. On January 13, 2005, CompSouth filed the Second Supplemental Direct Testimony of witness Gillan, and on January 14, 2005 the Public Staff filed the Supplemental Testimony of witness Johnson.

On January 27, 2005, in response to the joint request of the Public Staff and Verizon, the Commission issued an Order Rescheduling Evidentiary Hearing to March 9, 2005. On March 1, 2005, Verizon and the Public Staff advised the Commission that they had reached an agreement in principle regarding the terms of an amended price regulation plan for Verizon and requested a suspension of the hearing. On March 3, 2005, in response to the joint motion, the Commission issued an Order Suspending Hearing.

Public notice in the form approved by the Commission was mailed to each Verizon customer as ordered by the Commission and was published in newspapers within the State of North Carolina, with publication in each newspaper being made at least twice as evidenced by the Affidavits of Publication filed by Verizon with the Commission on February 3, 2005.

On March 18, 2005, Verizon filed with the Commission a "Stipulation and Agreement Between Verizon and Public Staff," attached to which was a copy of the price regulation plan stipulated to by Verizon and the Public Staff (the "Stipulated Plan"). In this filing, Verizon asked that the Commission establish a procedural schedule that included the filing of testimony regarding the Stipulated Plan on or before April 4, 2005; that the testimony previously filed be stipulated into evidence; and that a hearing on the Stipulated Plan be set for April 18, 2005.

On March 22, 2005, the Commission issued its Order Scheduling Hearing on Stipulation, which provided for an evidentiary hearing on April 18, 2005. This order provided that additional testimony in support of or in opposition to the Stipulated Plan was to be filed on or before April 4, 2005; that testimony previously prefiled by witnesses for all of the parties would be entered in the record as evidence; that, unless a party made a filing not later than April 7, 2005, requesting an opportunity to cross-examine a particular witness, it would not be necessary for that witness to appear and testify at the hearing; that witness lists, preferred order of witnesses and estimated cross-examination times be filed by April 7, 2005; and that briefs and proposed orders would be due 14 days from the close of the hearing.

On April 4, 2005, Verizon filed the Further Direct Testimony of witness Danner, and the Public Staff filed the direct testimony of Charles B. Moye, an Engineer with the Communications Division, both in support of the Stipulated Plan. No party requested the appearance of any other witness at the April 18 hearing.

At the April 18, 2005 evidentiary hearing in Raleigh, the only parties present were Verizon and the Public Staff. The testimony of Verizon witness Danner and that of Public Staff witness Moye were tendered into the record without objection. A Joint Proposed Order was filed by Verizon and the Public Staff on May 2, 2005. On that same date, the Attorney General filed a brief in opposition to the Stipulated Plan.

WHEREUPON, based on the foregoing, the evidence adduced at the hearing, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Verizon is a "local exchange company" as that term is defined in G.S. 62-3(16a) and is subject to the provisions of G.S. 62-110(f1). Verizon 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 Verizon 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.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 1

Finding of Fact and Conclusion of Law No. 1 is supported by the record as a whole and is not contested.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 2 - AFFORDABILITY

Finding of Fact and Conclusion of Law No. 2 (and Nos. 3-5 as well) are supported by the testimony and exhibits of Verizon witnesses Fulp, Danner, Duncan and Leo and Public Staff witnesses Johnson and Moye, together with the RTI Report. The Commission has also taken into consideration the testimony of CompSouth witness Gillan (although this witness did not specifically address the Stipulated Plan) and the brief filed by the Attorney General setting forth certain arguments in opposition to approval of the Stipulated Plan.

Verizon witnesses Danner, Duncan and Leo testified as to the economic rationale supporting the need to revise Verizon's Original Plan; the economic context in which revisions to the Original Plan should be evaluated; the recent changes in the competitive landscape for telecommunications services in the United States and in North Carolina, both intramodal and intermodal; the effects of these changes on the proper role of regulation with respect to the pricing of services; why service penalties are not necessary; and the reasons why Verizon believes there is no longer a need for an explicit productivity offset in its price regulation plan. Witness Fulp testified as to the specific provisions of the June 2004 Revised Plan and the reasons for the changes that had been made from the Original Plan. Witness Johnson presented a critique of the June 2004 Revised Plan, asserting that this plan would allow Verizon an excessive degree of pricing flexibility because effective competition does not yet exist with respect to certain services and in certain geographical areas in Verizon's service area.

In his Further Direct Testimony, witness Danner discussed the detailed provisions of the Stipulated Plan, explained why it is consistent with the requirements of G.S. 62-133.5(a) and (c), and stated that it represents a fair compromise between Verizon's initial position in this case and that of the Public Staff. Witness Danner's initial direct and rebuttal testimony, as well as that of witnesses Fulp, Duncan and Leo, provided clear evidence that Verizon has experienced a net loss of access lines to competition, that such losses continue to date, and that there is virtually no prospect of a reversal of this trend. These witnesses testified to significant risk for traditional wireline local telephone companies from competition from wireless and voice over internet protocol (VoIP) providers as well as from CLPs. Their testimony establishes that for many services in Verizon's service areas, price constraints imposed by the existence of competitors are current, real and generally effective, aiding our determination that the Stipulated Plan will result in affordable rates. Witness Moye testified as to the differences between the Stipulated Plan and the Original Plan, and he expressed the opinion that the Stipulated Plan satisfies the criteria of G.S. 62-133.5(a) and (c). Like witness Danner, he indicated that the Stipulated Plan is a reasonable compromise between the positions of Verizon and the Public Staff.

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 Original Plan, this service is included in the Basic category; in the Stipulated Plan, it is included in the analogous Moderate Pricing Flexibility Services category. However, the Stipulated Plan allows Verizon greater flexibility to adjust the price of basic local exchange service than the Original Plan. Under the Original Plan, aggregate annual price changes for Basic Services were limited to the rate of inflation as measured by the annual change in the Gross Domestic Product Price Index ("GDPPI"), minus a productivity offset of 2%; in the Stipulated Plan the offset is reduced to zero, and the basket cap is set at one and one-half times the rate of inflation. As witness Duncan noted, a productivity offset was justifiable when price regulation was initially adopted and competition in local telephone service had not developed. However, now that some local telephone services are competitive and not subject to price constraints, an offset is no longer warranted. Under the Original Plan, the maximum annual price increase for any rate element in the Basic category was equal to the change in GDPPI plus 3%; under the Stipulated Plan, individual rate elements in the Moderate Pricing Flexibility Services category can be increased by up to 10% per year. The Stipulated Plan also includes a minimum increase provision, under which any rate element in the Moderate Pricing Flexibility Services category may be increased by a minimum of \$0.35 annually if it is priced on a flat-rated monthly basis and \$0.15 annually if it is priced on a per-use basis, even if this increase exceeds 10%.

Notwithstanding the position taken by the Attorney General, the Commission 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 one and one-half times the rate at which there is a change in prices for other goods and services in the general economy. 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 in order to be compliant with the Stipulated Plan's aggregate pricing restrictions. The Stipulated Plan further protects the affordability of basic local exchange services by generally limiting the potential annual price increase for any single rate element to 10%.

Furthermore, the record shows that even with respect to basic local exchange service, Verizon has wireline competition in 98% of its exchanges and wireless competition in virtually every exchange.[1] In contrast, when the Original Plan was adopted in 1996, there was little or no

[1] Because of the lack of responses, the RTI Report discloses little about the status of competition between wireline and wireless providers or VoIP providers.

competition for basic service. The limited increase in pricing flexibility allowed under the Stipulated Plan for basic local exchange service is fully justified by the increased competition that exists in Verizon's North Carolina telecommunications market.

DISCUSSION OF 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 provisions for appropriate service quality penalties. The Commission retains powers and authority with regard to the provision of quality service. Verizon 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, we conclude that the Stipulated Plan reasonably assures the continuation of basic local exchange service that meets the reasonable service standards generally set forth in Commission Rule R9-8.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW
NO. 4 – NO PREJUDICE AMONG CUSTOMER CLASSES

Verizon witness Danner's Further Direct 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, with regard to mass-market customers, Verizon 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, witness Danner testified, the Stipulated Plan does not change any terms and conditions applicable to Verizon's relationships with other carriers, such as the terms of access tariffs, interconnection agreements, or wholesale services arrangements, and numbering and applicable non-discrimination requirements will remain in effect.

Fourth, the Stipulated Plan constrains the level of access charges and provides a special mechanism to permit access charge rebalancing to occur not only with respect to other Moderate Pricing Flexibility services, but also through High Pricing Flexibility services. Verizon's ability to adjust the prices of its other Moderate Pricing Flexibility services is also tied, in part, to potential reductions in carrier access charges. As competitive conditions warrant, the Stipulated Plan will thus facilitate related access charge reductions.

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 Verizon 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 Danner's analysis and agreed that the Stipulated Plan will not be unreasonably prejudicial to any customers.

The Commission finds the testimony of witnesses Danner and Moye to be persuasive and concludes that the Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW
NO. 5 – PUBLIC INTEREST STANDARD

The public interest standard is one the Commission has employed in its deliberations for many years. Notwithstanding the brief filed by the Attorney General setting forth certain arguments in opposition to approval of the Stipulated Plan, the Commission finds the Stipulated Plan to be in the public interest for several reasons. First, it permits the rate rebalancing necessary for the ongoing transition to competition, without allowing the rebalancing process to proceed at such a rapid pace as to impose an undue burden upon those customers whose rates may increase. Second, the Stipulated Plan provides affordable rates and assures that Verizon will continue to provide adequate service to its customers. Third, the Stipulated Plan contains specific service performance measures and penalties. Fourth, the Stipulated Plan properly places the risk of future investment decisions on Verizon's shareholders, which is where such risks must rest in a competitive marketplace, rather than on the ratepayers. Fifth, the Commission believes that a competitive marketplace is consistent with the goals established by the legislature, and will engender significant benefits for the citizens of the State through improved services, generally lower prices, and greater technological innovation, and that it will therefore offer significant potential for enhanced economic development.

At the same time, the Commission recognizes that the public interest could be adversely affected if telecommunications services were fully deregulated, or regulated so lightly that the only limitations on prices were those imposed by competition, at a time when competition had not yet progressed to the point where it could discipline prices effectively in every market area in Verizon's North Carolina service territories.

In addressing this concern, the Commission notes that there is a close correlation between the assignment of telecommunications services to pricing categories under the Stipulated Plan and the degree of competition for particular services in Verizon's service area. The assignment of services to categories in the Stipulated Plan was determined by negotiation between Verizon and the Public Staff; however, a review of the RTI Report, as well as the data furnished by Verizon in the discovery process, discloses that the services assigned to the Total Pricing Flexibility Services category are those as to which the greatest degree of competition exists. In contrast, the services categorized as Moderate Pricing Flexibility Services are those for which competition is less vigorous. The Commission finds it significant that the Public Staff, which is responsible under G.S. 62-15 for protecting the interests of the using and consuming public, has been willing to agree to the Stipulated Plan. In addition, the Commission notes that no party filed testimony in opposition to the Stipulated Plan, although the Attorney General did file a brief in opposition thereto. 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 interest standards, to decide complaints concerning anticompetitive behavior, and to oversee the reclassification and regrouping of services and the financial impacts of governmental actions.

Accordingly, while still concerned about the irreversible nature of the Stipulated Plan, the Commission nevertheless concludes that the changes effected by the Stipulated Plan are sufficiently limited, and that the current level of competition in Verizon's local exchange service area is sufficiently advanced, that these changes are consistent with the public interest given the current level of competition in Verizon's service territories. Furthermore, the Commission recognizes that, under the Stipulated Plan, it retains the same regulatory oversight authority as afforded under the Original Plan for any request by Verizon 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, Verizon and the Public Staff have negotiated a Stipulated Plan that meets each of the criteria prescribed by G.S. 62-133.5(c) and therefore the Commission finds that approval of the Stipulated Plan is appropriate. A comparison of the Stipulated Plan, the June 2004 Revised Plan, and the plan proposed by Public Staff witness Johnson reveals the extent of Verizon's and the Public Staff's efforts to reach common ground. The record shows that the competitive landscape has changed considerably since the Original Plan was approved. The Commission believes that the additional flexibility afforded by the Stipulated Plan will enable Verizon to compete effectively and continue to provide reasonably affordable basic local exchange service. The Commission's decision to approve the Stipulated Plan is based upon its analysis of competitive conditions in Verizon's service territories, 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 Verizon effective not later than Thursday, June 9, 2005, provided that Verizon shall, not later than Monday, May 16, 2005, refile the Stipulated Plan bearing an effective date not later than June 9, 2005.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of May, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

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DOCKET NO. P-55, SUB 1013

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of BellSouth Telecommunications, Inc. for, and Election of, Price Regulation	)))	NOTICE OF DECISION AND ORDER

HEARD IN: Commission Hearing Room 2115, Dobbs Building, Raleigh, North Carolina, on November 29, 2004, through December 1, 2004

BEFORE: Chairman Jo Anne Sanford, Presiding, and Commissioners J. Richard Conder, Robert V. Owens, Jr., Sam J. Ervin, IV, Lorinzo L. Joyner, James Y. Kerr, II, and Michael S. Wilkins[1]

APPEARANCES:

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[1] Commissioner Wilkins resigned from the Commission effective January 31, 2005, and did not participate in deciding this case.

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BY THE COMMISSION: This matter arose on February 26, 2004, upon the filing by BellSouth Telecommunications, Inc. (BellSouth or Company) of a request for revisions to the price regulation plan under which the Company is currently operating.

Subsequently, petitions to intervene were filed by Covad Communications, Inc. and the Concord Telephone Company, which were granted by the Commission. Previously authorized intervenors (including Carolina Utility Customers Association, Inc. (CUCA), AT&T Communications of the Southern States, LLC. (AT&T), Carolina Telephone and Telegraph Company and Central Telephone Company (collectively Sprint), MCI Metro Access Transmission Services, LLC, MCI WorldCom Communications, Inc. and MCI WorldCom Network Services, Inc. (collectively MCI), Southeastern Competitive Carriers Association (SECCA), Competitive Carriers of the South (CompSouth), the United States Department of Defense and All Other Federal Executive Agencies (DoD/FEA), the North Carolina Department of Justice (Attorney General) and the Public Staff – North Carolina Utilities Commission (Public Staff)) participated in the case.

By Order issued June 9, 2004, the Commission set the matter for the hearing on November 29, 2004, and established a procedural schedule, which included the filing of testimony regarding the study of local service competition in North Carolina (Report) by Research Triangle Institute (RTI). On July 16, 2004 the Commission adopted procedures governing discovery, including the service of discovery on RTI.

By Commission Orders issued July 16, 2004, September 16, 2004, and October 22, 2004, a revised procedural schedule was established requiring BellSouth to prefile its direct testimony by July 1, 2004, the Public Staff and other interveners to prefile their direct testimony by September 20, 2004, BellSouth to prefile its rebuttal testimony by October 21, 2004 and all parties to prefile supplemental testimony regarding the RTI Report by November 22, 2004.

On November 10, 2004 the Commission notified all parties that the RTI Report would be admitted into evidence, and unless objections were received by November 15, 2004, RTI would not be required to present a sponsoring witness. No objections were received; however, CUCA requested that all RTI discovery responses be entered into the record as well. By Order dated November 18, 2004, the RTI Report and related discovery were entered into the record.

The matter came on for hearing on November 29, 2004, before the full Commission. BellSouth presented the testimony and exhibits of John A. Ruscilli, Senior Director of State Regulatory for BellSouth; Pamela A. Tipton, a Director of Interconnection Services; Venessa Harrison, a Manager of Regulatory and External Affairs; and Aniruddha Banerjee, Ph.D., consulting economist and Vice President of NERA Economic Consulting. CompSouth presented the testimony and exhibits of consulting economist Joseph Gillan. AT&T presented the testimony and exhibits of William J. Barta, a consultant with Henderson Ridge Consulting, Inc. MCI presented the testimony and exhibits of Greg Darnell, Senior Manager-Regulatory Economics for MCI, Inc. The Department of Defense presented the testimony of Harry Gildea, a consultant with Snavely King Majoros O'Connor & Lee, Inc. The Public Staff presented the testimony and exhibits of Ben Johnson, Ph.D., a consulting economist and President of Ben Johnson Associates, Inc. The Attorney General, SECCA, and CUCA did not present testimony.

The parties were granted an extension of time to file proposed orders and briefs. On January 28, 2005, the Public Staff filed its proposed order, and post hearing briefs were filed by AT&T, BellSouth, CUCA, CompSouth, MCI, and SECCA. After receiving an extension of time to file, on February 1, 2005 the Attorney General filed his post hearing brief.

On February 11, 2005, the Public Staff filed its Statement of Revised Position and Proposal for Settlement.

On February 15, 2005, the Commission issued an Order requesting comments from all parties in response to the Public Staff's Statement of Revised Position. The Commission required initial comments to be filed not later than February 21, 2005 and reply comments from the Public Staff to be filed not later than February 28, 2005. The Commission indicated that it might also convene an oral argument to consider the Public Staff's settlement proposal and the parties' responses thereto on an expedited basis.

On February 16, 2005, SECCA filed a motion whereby the Commission was requested to modify the procedural schedule set forth in the February 15, 2005 Order by allowing all parties, not just the Public Staff, to file reply comments on February 28, 2005.

On February 18, 2005, the Commission issued its Order Granting Request to Modify Procedural Schedule. In its Order, the Commission granted SECCA's February 16, 2005 motion, thereby allowing all parties to file reply comments. However, the Commission found that the parties would not be allowed to raise new issues in their reply comments.

On February 21, 2005, BellSouth filed its Response to the Public Staff's Revised Position and Settlement Proposal. On that same date, CompSouth and CUCA also filed comments on the Public Staff's Revised Position and Settlement Proposal.

On February 28, 2005, reply comments were filed by the Attorney General, BellSouth, CUCA, DoD/FEA, MCI, the Public Staff, and SECCA.

On March 2, 2005, BellSouth filed its Final Proposed Price Plan Revisions with the Commission.

On March 3, 2005, the Commission issued its Order Requesting Comments. The Commission requested comments from all interested parties in response to BellSouth's Final Proposed Price Plan Revisions by no later than March 9, 2005.

On March 4, 2005, BellSouth filed copies of revised pages 6, 7, and 11 to its March 2, 2005 Final Proposed Price Plan Revisions and copies of the proposed service categories redlined to reflect changes that will be effective December 1, 2005 under BellSouth's proposal.

On March 9, 2005, comments on BellSouth's Final Proposed Price Plan Revisions were filed by CUCA, Pay Tel Communications, Inc. (Pay Tel), the Public Staff, and SECCA.

Statutory Requirements

G.S. 62-133.5(c) provides in pertinent part as follows:

> Any local exchange company subject to price regulation under the provisions of subsection (a) of [G.S. 62-133.5] may file an application with the Commission to modify such form of price regulation or for other forms of regulation. . . .Upon application, the Commission shall approve such other form of regulation upon finding that the plan as proposed (i) protects the affordability of basic local exchange service, as such service is defined by the Commission; (ii) reasonably assures the continuation of basic local exchange service that meets reasonable service standards established by the Commission; (iii) will not unreasonably prejudice any class of telephone customers, including telecommunications companies; and (iv) is otherwise consistent with the public interest. If the Commission disapproves, in whole or in part, a local exchange company's application to modify its existing form of price regulation, the company may elect to continue to operate under its then existing plan previously approved under this subsection or subsection (a) of [G.S. 62-133(5)].

In order to approve BellSouth's proposed revisions to its price regulation plan, the Commission must find that the proposed plan meets all four criteria set forth in G.S. 62-133(5)(c). If the Commission determines the plan does not meet all of the four criteria, the Commission must disapprove the plan as proposed. The Company may then either elect to continue to operate under its current plan or submit a new proposed plan.

CONCLUSIONS

The four criteria that the Commission must apply in assessing a price regulation plan or modifications to it are set out in G.S. 62-133.5(c). After careful consideration of the entire record, the Commission concludes that BellSouth's proposed price plan revisions, as filed, do not meet the four statutory criteria that must be met under G.S. 62-133.5(c). Therefore, the Commission cannot accept and approve either the amendments initially proposed by BellSouth to its Price Regulation Plan or its Final Proposed Price Plan Revisions.

Nevertheless, the Commission believes that it can approve a modified price regulation plan for BellSouth which does meet the four statutory criteria set out in G.S. 62-133.5(c). The

Commission recognizes that the BellSouth service territory differs from the service territories of other incumbent telecommunications providers in the State of North Carolina with respect to the extent and intensity of competitive activity. It thus follows that the degree and form of regulatory oversight among providers should vary as a function of these differences in demographics, density, and levels of competition. Therefore, the Commission finds good cause to announce that, subject to BellSouth's agreement, BellSouth's Final Proposed Price Plan Revisions as filed on March 2 and March 4, 2005, will be approved by the Commission subject to incorporation of the following modifications:

1. The services initially included in each of the three price plan baskets will generally be as proposed by BellSouth in its Final Proposed Price Plan Revisions filed on March 2, 2005 (Attachment A, Exhibits 1 through 3), except that local directory assistance service will be included in the High Pricing Flexibility Basket rather than the Total Pricing Flexibility Basket.
2. Local directory assistance service will continue to be provided as a tariffed service in the High Pricing Flexibility Basket and no free call allowances will be eliminated except upon express approval from the Commission.
3. Effective December 1, 2005, all services initially included in the Total Pricing Flexibility Basket will be detariffed. In addition, on that same date, all business services [excluding simple and complex individual business line services, all 911 services, all switched access services, equipment for disabled customers, and any other business services included by BellSouth in the Moderate and High Pricing Flexibility Baskets in its "Revised Price Regulation Service Categories – December 1, 2005" filed on March 4, 2005 (Attachments A and B)] initially included in the Moderate and High Pricing Flexibility Baskets will be detariffed and those detarrifed services will be moved to the Total Pricing Flexibility Basket. Rates for the business services previously contained in the Moderate Pricing Flexibility Basket, although detariffed and moved to the Total Pricing Flexibility Basket effective December 1, 2005, will be capped until December 1, 2006.
4. The services included in each of the three price plan baskets effective December 1, 2005, will generally be as proposed by BellSouth in its "Revised Price Regulation Service Categories – December 1, 2005" filed on March 4, 2005 (Attachments A, B, and C), except that local directory assistance service will remain in the High Pricing Flexibility Basket.
5. The service measurements for local operator "0" answertime and directory assistance answertime will remain in Section XI of the plan.
6. Affected customers, whether receiving tariffed and/or detariffed services, must be given at least 14 days' written notice of any price increase for a public utility service and before any public utility service offering is discontinued. The following provision should be included in the Plan: "BellSouth will provide customer notification of any price increase or discontinuance of service to all affected customers by written notice, which may include, but is not limited to, bill message, bill insert or direct mail, at the option of the Company, to all affected customers at least 14 days before any public utility tariffed or detariffed rates are increased or any tariffed or detariffed service is discontinued."
7. All new services offered after the effective date of the revised plan will be classified as Total Pricing Flexibility Services and placed in that Basket and those services will be detariffed on December 1, 2005. Commission approval will be required

prior to the elimination or discontinuance of any service that remains tariffed after December 1, 2005.

8. New and existing packages and bundled services will be included in the Total Pricing Flexibility Services category, provided that BellSouth agrees that notice of the individual regulated services included in packages and bundles, along with their individual rates, will be provided on the Company website. Service representatives will be required to inform any customer prior to actually placing an order for bundled or packaged services that individual services are also available on a standalone basis.

9. Section IX of the plan regarding Commission Oversight will be amended to read as follows: "The Commission retains oversight for service quality, complaint resolution and compliance by the Company with all elements of the Plan and applicable state law. The Company will file an Annual Report in the format adopted by the Commission for price regulated companies under Commission Rule R1-32 pursuant to Order dated April 16, 2004 in Docket No. P-100, Sub 72b. No other periodic financial reports are required to be filed with the Commission under this Plan."

Accordingly, the Commission hereby invites and requests BellSouth, subject to the guidance provided by this Order, to accept the modifications set forth above and to file an amended price regulation plan for final approval by the Commission. If BellSouth accepts the terms of this Order and files a fully-compliant revised plan, the Commission will approve that plan without further hearing or comment.

An Order setting forth the Commission's rationale in support of this decision will be issued subsequently. The Commission will consider the time for filing notice of appeal in this proceeding to run from the date of issuance of such further Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of March, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

Bb032405.01

DOCKET NO. P-55, SUB 1013

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of BellSouth Telecommunications,	)	ORDER APPROVING
Inc. for, and Election of, Price Regulation	)	BELLSOUTH'S
	)	MODIFIED PRICE
	)	REGULATION PLAN

BY THE COMMISSION: On March 24, 2005, the Commission issued its *Notice of Decision and Order* in this docket. In its Order, the Commission invited and requested BellSouth Telecommunications, Inc. (BellSouth) to accept the modifications set forth in the Order and to file an amended price regulation plan for final approval by the Commission. The Commission noted that if BellSouth accepted the terms of the Order and filed a fully-compliant revised plan, the Commission would approve the plan without further hearing or comment.

On March 30, 2005, BellSouth filed its Response to Notice of Decision and Order. BellSouth stated that it has decided to accept the modifications outlined in the *March 24, 2005 Order.* In addition, BellSouth stated that it was filing a fully-compliant revised plan as requested in the *March 24, 2005 Order.*

On March 31, 2005, BellSouth filed a corrected version of its modified plan which incorporated certain minor editorial and typographical changes requested by the Commission Staff.

WHEREUPON, the Commission has reviewed BellSouth's compliant modified plan as filed on March 31, 2005 and finds good cause to approve said plan to become effective on or after the date of this Order.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the _1st_ day of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp040105.01

DOCKET NO. P-772, SUB 8
DOCKET NO. P-913, SUB 5
DOCKET NO. P-989, SUB 3
DOCKET NO. P-824, SUB 6
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.	)	RECOMMENDED ARBITRATION ORDER

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on January 11 through 13, 2005

BEFORE: Commissioner James Y. Kerr, II, Presiding, and Commissioners Robert V. Owens, Jr., and Lorinzo L. Joyner

APPEARANCES:

For NewSouth Communications Corp., NuVox Communications, Inc., KMC Telecom V, Inc., KMC Telecom III, LLC, and Xspedius Management Co. Switched Services, LLC:

Garret R. Hargrave, John J. Heitmann, and Stephanie A. Joyce, Kelley, Drye & Warren LLP, 1200 19th Street N.W., Suite 500, Washington, DC 20036

Henry C. Campen, Jr., Parker, Poe, Adams & Bernstein, LLP, Wachovia Capitol Center, 150 Fayetteville Street Mall, Suite 1400, P.O. Box 389, Raleigh, North Carolina 27602-0389

For BellSouth Telecommunications, Inc.:

James Meza, III and Robert Culpepper, BellSouth Telecommunications, Inc., Suite 4300, BellSouth Center, 675 West Peachtree Street, N.E., Atlanta, Georgia 30375

Edward L. Rankin, III, 1521 BellSouth Plaza, 300 South Brevard Street, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: This matter is before the Commission pursuant to Sections 251 and 252 of the Telecommunications Act of 1996 (TA96 or the Act), North Carolina General Statute 62-110(f1), and various Commission Orders, on a Joint Petition of NewSouth Communications Corp. (NewSouth), NuVox Communications, Inc. (NuVox), KMC Telecom V, Inc. and KMC Telecom III, LLC (together, KMC), and Xspedius Communications, LLC on behalf of its operating subsidiary, Xspedius Management Co. Switched Services, LLC (collectively Xspedius) (collectively, Joint Petitioners or Petitioners) requesting the Commission to arbitrate unresolved issues that arose in negotiations with BellSouth Telecommunications, Inc. (BellSouth) for interconnection agreements (Agreements or ICAs).

BACKGROUND

Section 251 of the Act requires each incumbent local exchange carrier (ILEC) to provide interconnection to requesting telecommunications carriers with the ILEC's network and unbundled access to network elements on rates, terms, and conditions that are just, reasonable, and nondiscriminatory in accordance with the terms and conditions of the ICA and Section 252. Section 252(b) provides for arbitration by state regulatory commissions of unresolved issues between ILECs and requesting carriers concerning ICAs and network elements.

FCC Proceedings

In its *Triennial Review Order (TRO)*[1], the Federal Communications Commission (FCC) made significant changes to the rules regarding ILECs' unbundling obligations. Because the *USTA II* decision vacated and remanded significant portions of the FCC's unbundling rules, the FCC took several steps to avoid excessive disruption of the local telecommunications market while it wrote new rules. On July 13, 2004, the FCC released an order that replaced the so-called "pick-and-choose rule" with a new "all-or-nothing rule" designed to facilitate commercial agreements between ILECs and competing local providers (CLPs).[2] On August 9, 2004, the FCC held that fiber loops deployed at least to the minimum point of entry (MPOE) of multiple dwelling units (MDUs) that are predominantly residential should be treated as fiber-to-the-home (FTTH) loops for unbundling purposes, irrespective of the ownership of the inside wiring.[3]

On October 18, 2004, the FCC determined that fiber-to-the-curb (FTTC) deployments should be treated in the same manner as FTTH deployments for unbundling purposes so long as the fiber deployment is not farther than 500 feet from each customer premises reached from the serving area interface.[4] The *FTTC Reconsideration Order* clarified that ILECs are not required

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[1] *Review of the Section 251 Unbundling Obligations of Incumbent Local Exchange Carriers; Implementation of the Local Competition Provisions of the Telecommunications Act of 1996; Deployment of Wireline Services Offering Advanced Telecommunications Capability*, CC Docket Nos. 01-338, 96-98, 98-147, Report and Order and Order on Remand and Further Notice of Proposed Rulemaking, 18 FCC Rcd. 16978, 17145, ¶ 278 (2003) (*Triennial Review Order* or *TRO*), *corrected by* Errata (*Errata*), 18 FCC Rcd. 19020 (2003), *vacated and remanded in part, affirmed in part, United States Telecom Ass'n. v. FCC*, 359 F.3d 554 (D.C. Cir. 2004) (*USTA II*) *cert. denied*, 125 S.Ct. 313 (2004).

[2] *Review of the Section 251 Unbundling Obligations of Incumbent Local Exchange Carriers*, CC Docket No. 01-338, Second Report and Order, 19 FCC Rcd. 13494 (2004).

[3] *Review of the Section 251 Unbundling Obligations of Incumbent Local Exchange Carriers; Implementation of the Local Competition Provisions of the Telecommunications Act of 1996; Deployment of Wireline Services Offering Advanced Telecommunications Capability*, CC Docket Nos. 01-338, 96-98, 98-147, Order on Reconsideration, 19 FCC Rcd. 15856 (2004) (*MDU Reconsideration Order*).

[4] *Review of the Section 251 Unbundling Obligations of Incumbent Local Exchange Carriers; Implementation of the Local Competition Provisions of the Telecommunications Act of 1996; Deployment of*

to build time domain multiplexing (TDM) capability into new packet-based networks or into existing packet-based networks without TDM capability. On October 27, 2004, the FCC released an order granting the four Bell Operating Companies (BOCs) forbearance relief from the requirements of Section 271 of the Act with regard to broadband elements to the same extent that unbundling relief was granted under Section 251.[1]

Another step was the August 20, 2004 release of the *Interim Order*[2] in which the FCC required carriers, for a limited period of time, to adhere to the commitments made in their interconnection agreements, applicable statements of generally available terms and conditions (SGATs) and relevant state tariffs in effect as of June 15, 2004. The FCC also set forth and sought comment on a transition plan under which, for the subsequent six months, if no final unbundling rules had been issued, the same commitments to provide network elements would apply to existing customers, but not new customers, at modestly higher rates than those available on June 15, 2004.

Finally, subsequent to the hearing in this docket, the FCC issued its *Triennial Review Remand Order (TRRO)* on February 4, 2005.[3] In the *TRRO*, the FCC put in place new rules applicable to ILECs' unbundling obligations with regard to mass market local circuit switching, high-capacity loops, and dedicated interoffice transport. Paragraph 235 of the *TRRO* specifies that the rules implementing the Order became effective on March 11, 2005.

Instant Proceeding

On February 11, 2004, the Joint Petitioners filed a Petition requesting the Commission to arbitrate an interconnection agreement between them and BellSouth and waive its requirement that prefiled testimony be filed contemporaneously with the Petition because negotiations were proceeding and there was a realistic prospect of a reduction in the number of issues. On February 12, 2004, the Commission issued an Order setting dates for the filing of a response to the Petition and prefiling of testimony by the parties.

On February 23, 2004, BellSouth asked that the proceeding be severed into four separate arbitration proceedings (i.e., one for each CLP) or that the Joint Petitioners be required to proceed as if they constituted a single entity with regard to contested issues and presentation and cross-examination of witnesses. On March 3, 2004, the Joint Petitioners responded to BellSouth's motion, and on March 11, 2004, BellSouth replied. On March 22, 2004, the Commission denied the motion to sever and established procedural restrictions for the

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Wireline Services Offering Advanced Telecommunications Capability, CC Docket Nos. 01-338, 96-98, 98-147, Order on Reconsideration, 19 FCC Rcd 20293 (2004) (*FTTC Reconsideration Order*).

[1] *Petition for Forbearance of the Verizon Telephone Companies Pursuant to 47 U.S.C. § 160(c); SBC Communications Inc.'s Petition for Forbearance Under 47 U.S.C. § 160(c); Qwest Communications International Inc. Petition for Forbearance Under 47 U.S.C. § 160(c); BellSouth Telecommunications, Inc. Petition for Forbearance Under 47 U.S.C. § 160(c)*, WC Docket Nos. 01-338, 03-235, 03-260, 04-48, Memorandum Opinion and Order, 19 FCC Rcd. 21496 (2004).(*Broadband 271 Forbearance Order*).

[2] *Unbundled Access to Network Elements; Review of the Section 251 Unbundling Obligations of Incumbent Local Exchange Carriers*, CC Docket No. 01-338, WC Docket No. 04-313, Order and Notice of Proposed Rulemaking, 19 FCC Rcd 16783 (2004) *(Interim Order)*.

[3] *Unbundled Access to Network Elements and Review of the Section 251 Unbundling Obligations of Incumbent Local Exchange Carriers*, Order on Remand, FCC 04-290, rel. February 4, 2005. (*TRRO*).

proceedings. On March 26, 2004, the Commission granted BellSouth's motion to revise the filing dates and hearing.

The Public Staff filed a Notice of Intervention on April 1, 2004.

On April 30, 2004, the Joint Petitioners filed the direct testimony of Raymond Chad Pifer, Marva Brown Johnson, and Brian C. Murdoch on behalf of KMC; John Fury on behalf of NewSouth; Jerry Willis and Hamilton Russell on behalf of NuVox; and James Falvey on behalf of Xspedius.

On May 4, 2004, BellSouth filed a motion for reconsideration of the Commission's March 22, 2004, *Order Denying Motion to Sever and Imposing Procedural Restrictions*. The Joint Petitioners responded to BellSouth's motion on May 7, 2004, and the Public Staff filed comments on the motion on May 10, 2004. On May 13, 2004, the Commission issued an Order denying BellSouth's motion and authorizing the presentation of the Joint Petitioners' testimony by a single panel made up of all of the Joint Petitioners' witnesses.

BellSouth filed the direct testimony of Carlos Morillo and Eddie L. Owens; P. L. (Scot) Ferguson and Eric Fogle; and Kathy Blake on June 4, 2004.

On July 12, 2004, BellSouth and the Joint Petitioners requested that the Commission hold the proceeding in abeyance for a period of 90 days, thereby suspending all pending deadlines and consideration of all pending motions until after October 1, 2004, and waiving until June 2005 the deadline under Section 252(b)(4)(C) of the Act for final resolution by the Commission of the issues in this arbitration. By Order dated July 14, 2004 and *Errata Order* dated July 15, 2004, the Commission granted the motion. On October 1, 2004, the Commission granted the motion of the parties filed on September 29, 2004, for a further extension of filing dates.

BellSouth filed a Joint Revised Issues Matrix on October 15, 2004. Supplemental Direct Testimony of the Joint Petitioners witnesses Collins, Johnson, Pifer, Fury, Russell, Willis, and Falvey was filed on October 29, 2004. Supplemental Direct Testimony of BellSouth witnesses Blake, Ferguson, Fogle, Morillo, and Owens was filed on November 12, 2004. Rebuttal Testimony of the Joint Petitioners witnesses was filed on December 3, 2004.

On January 3, 2005, the Joint Petitioners provided notice that the testimony of witness Fury would be adopted by witness Willis in its entirety.

On January 10, 2005, the Joint Petitioners filed an Updated Issues Matrix and Direct and Rebuttal Testimony Errata.

This matter came on for hearing as scheduled beginning on January 11, 2005. The Joint Petitioners offered the testimony, supplemental testimony, rebuttal testimony, and exhibits of witnesses Pifer, Johnson, and Murdoch on behalf of KMC; Fury on behalf of NewSouth; Willis and Russell on behalf of NuVox; and Falvey on behalf of Xspedius. BellSouth offered the testimony, supplemental testimony, and exhibits of witnesses Morillo, Owens, Ferguson, Fogle, and Blake.

By stipulation of the Joint Petitioners and BellSouth, Matrix Item Nos. 23, 108, 109, 110, 111, 112, 113, and 114 would be addressed in the parties' briefs only. The parties waived cross-examination and redirect examination of those items.

On March 31, 2005, the Joint Petitioners and BellSouth filed a joint motion to move certain issues to the change of law proceeding.

By Order dated April 4, 2005, the Commission granted the parties' motion to find Matrix Item Nos. 109, 110, and 112 moot and to transfer Matrix Item Nos. 23, 108, 111, 113, and 114 to the change of law proceeding in Docket No. P-55, Sub 1549 for resolution, to be followed at the appropriate time by referral back to these dockets for incorporation in the arbitrated agreements.

After being granted an extension of time to file Briefs and Proposed Orders, on April 8, 2005, BellSouth filed its Post-Hearing Brief, the Joint Petitioners filed their Proposed Order and Post-Hearing Brief, and the Public Staff filed its Proposed Order in these dockets.

On May 10, 2005, at the request of the Commission Staff, BellSouth filed an amended Exhibit A to its Post-Hearing Brief.

On May 27, 2005, KMC filed its Notice of Withdrawal with Prejudice. KMC stated that it was notifying the Commission that it was withdrawing its participation in these dockets with prejudice. KMC stated that its withdrawal, with prejudice, applies only to KMC and does not apply to any of the other remaining Joint Petitioners in the arbitration proceeding. By Order dated June 2, 2005, the Commission allowed KMC's withdrawal from this proceeding, with prejudice.

Appendix A provides a list of the acronyms used in this *Recommended Arbitration Order (RAO)*.

Based on the foregoing and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. The term "End User" should be defined as "the customer of a party."

2. The industry standard limitation of liability limiting the liability of the provisioning party to a credit for the actual cost of services or functions not performed or improperly performed should apply.

3. If a party elects not to place standard industry limitations of liability in its contracts with end users or in its tariffs, that party shall indemnify the other party for any loss resulting from its decision not to include the limitation of liability.

4. The rights of end users should be defined pursuant to state contract law.

5. The Agreement should state that incidental, indirect, and consequential damages should be defined pursuant to state law.

6. The proposal of the Joint Petitioners found in Section 10.5 of their Appendix A should be approved.

7. The parties may seek resolution of disputes arising out of the Agreement from the Commission, FCC, or courts of law.

8. The Agreement should contain the language proposed by BellSouth as modified by the Conclusions in this issue.

9. BellSouth shall permit a requesting carrier to commingle an unbundled network element (UNE) or a UNE combination obtained pursuant to Section 251 with one or more facilities or services that the requesting carrier has obtained at wholesale from an ILEC pursuant to a method other than unbundling under Section 251(c)(3) of the Act. However, this does not include services, network elements, or other offerings made available only under Section 271 of the Act.

10. The term, line conditioning, should be defined in the Agreement as set forth in FCC Rule 51.319(a)(1)(iii)(A). BellSouth should perform line conditioning in accordance with FCC Rule 51.319(a)(1)(iii).

11. The line conditioning activity of load coil removal on copper loops should not be limited to copper loops with only a length of 18,000 feet or less.

12. Any copper loop ordered by a CLP with over 6,000 feet of combined bridged tap will be modified, upon request from the CLP, at no additional charge, so that the loop will have a maximum of 6,000 feet of bridged tap. Line conditioning orders that require the removal of other bridged tap (bridged tap between 0 and 6,000 feet) should be performed at the BellSouth UNE rates previously adopted by the Commission.

13. 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 its 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 after the audit has been concluded. BellSouth is not required to provide documentation to support its basis for an audit, as distinct from a statement of concern, or seek concurrence of the requesting carrier before selecting the audit's location.

14. BellSouth should not be permitted to charge a Tandem Intermediary Charge (TIC) when providing a tandem transit function for CLPs.

15. The Joint Petitioners' proposed language concerning how disputes over alleged unauthorized access to customer service record (CSR) information should be handled under the Agreement is reasonable and appropriate. Accordingly, the Commission adopts the Joint

Petitioners' proposed language for Sections 2.5.5.2 and 2.5.5.3 of Attachment 6 of the Agreement.

16. BellSouth must provide service expedites at total element long-run incremental cost (TELRIC)-compliant rates. BellSouth and the Joint Petitioners are instructed to negotiate in good faith an appropriate rate for service expedites. If the parties are unable to negotiate a rate, BellSouth should submit a TELRIC cost study for the Commission's review and approval.

17. The payment due date should be 26 days from the date of receipt of the bill. Accordingly, the Commission requires the Joint Petitioners and BellSouth to properly amend the proposed language in the Agreement in Attachment 7, Section 1.4, in accordance with this decision.

18. It is appropriate to adopt the Joint Petitioners' proposed language concerning suspension or termination notices for Section 1.7.2 of Attachment 7 of the Agreement.

19. The deposit requirements specified in Commission Rule R12-4 are applicable and the language proposed by BellSouth should be incorporated into the Agreement.

20. The Joint Petitioners should not be allowed to offset security deposits by amounts owed to them by another carrier, but may exercise other options to address late payments, such as the assessment of interest or late payment charges, suspension of service, or disconnection after notice.

21. The language proposed by BellSouth with respect to termination of service due to non-payment of a deposit for Section 1.8.6 is appropriate.

22. The language proposed by the Joint Petitioners on the need for or amount of a deposit to be included in Section 1.8.7 of the Agreement is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

ISSUE NO. 1 – MATRIX ITEM NO. 2: How should "End User" be defined?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners argued that the term "End User" should be defined as "the customer of a Party." The Joint Petitioners noted that the term "End User" will apply in numerous contexts in the Agreement. It will define customers that the Joint Petitioners may serve, including wholesale customers. BellSouth's definition is more lengthy and complex and hard to apply. It also appears to limit the term to a listing of specific entities, apparently motivated by concern on BellSouth's part that the Joint Petitioners will not use UNEs in accordance with the law, as well as the concept that certain services are not "qualified" for UNEs. Joint Petitioners pointed out that they are not limited in their use of UNEs, with the exception of enhanced extended links (EELs) and that the notion of "qualifying services" has been vacated under *USTA II*.

BELLSOUTH: BellSouth argued that the Joint Petitioners should not be permitted to use the definition of "End User" in a way that will result in their obtaining UNEs in a prohibited manner, including violation of the EEL eligibility criteria. BellSouth proposed three definitions that it maintained would meet both its own and the Joint Petitioners' concerns:

> "End User," as used in this Interconnection Agreement, means the retail customer of a Telecommunications carriers such as CLECs [competitive local exchange companies], ICOs [Independent Telephone Companies] and IXCs [interexchange carriers].
>
> "Customer," as used in this Interconnection Agreement, means the wholesale customer of a Telecommunications Service that may be an ISP [Internet service provider]/ESP [enhanced service provider], CLEC, ICO or IXC.
>
> "end user," as used in this Interconnection Agreement, means the End User or any other retail customer of a Telecommunications Service, including ISPs/ESPs, CLECs, ICOs, and IXCs, that are provided the retail Telecommunications Service for the exclusive use of the personnel employed by ISPs/ESPs, CLECs, ICOs and IXCs, such as the administrative business lines used by the ISPs/ESPs, CLECs, ICOs and IXCs at their business locations, where such ISPs/ESPs, CLECs, ICOs and IXCs are treated as End Users.

The first definition ("End User") is intended to distinguish between retail customers and wholesale customers/such as carriers. The second definition ("customer") is to be used where the provisions of service is to a carrier, such as a CLP or IXC. This would have particular relevance in relation to the eligibility criteria for EELs. The third definition ("end user") is meant to apply where a carrier is actually an end user in the traditional sense of the word.

PUBLIC STAFF: The Public Staff supported the Joint Petitioners' definition as being more straightforward and clear. Parties are obliged in any case to comply with all of the FCC's rules.

DISCUSSION

In this issue, the Commission is asked to decide whether to define "End User" as "the customer of a party," as advocated by the Joint Petitioners and Public Staff or whether to mandate the use of three terms – "End User" (with capitalized first letters), "customer," and "end user" (all lower case) – to express nuanced distinctions, ostensibly for the prevention of fraud, as advocated by BellSouth. The Commission agrees with the Joint Petitioners and the Public Staff that the BellSouth approach is more lengthy, overly complex, and difficult to apply consistently in a document as thick as an interconnection agreement. It also misses the mark. CLPs are already supposed to comply with applicable federal law and FCC rules and not to engage in fraud. The multiplication and complexification of definitions does not assist in this effort.

CONCLUSIONS

The Commission concludes that the definition of "end user" proposed by the Joint Petitioners should be included in the Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

ISSUE NO. 2 – MATRIX ITEM NO. 4: What should be the limitation on each party's liability in circumstances other than gross negligence or willful misconduct?

POSITIONS OF PARTIES

JOINT PETITIONERS: In cases other than gross negligence and willful misconduct by the other party, or other specified exemptions as set forth in the Joint Petitioners' proposed language, liability should be limited to an aggregate amount over the entire term equal to 7.5% of the aggregate fees, charges, and amounts paid or payable for any and all services provided or to be provided pursuant to the Agreement as of the day on which the claim arose.

BELLSOUTH: The industry standard limitation should apply, which limits the liability of the provisionary party to credit for the actual cost of the services or functions not performed or performed improperly.

PUBLIC STAFF: The Public Staff concurred with BellSouth's position.

DISCUSSION

This issue presents a choice between adoption of a "cap" of 7.5% of the amounts paid or payable for all services provided under the Agreement on the day the claim giving rise to liability arose, as advocated by the Joint Petitioners, or the payment of a credit for the actual cost of services or functions unperformed or performed improperly, as advocated by BellSouth.

The Joint Petitioners' proposal is that on a rolling basis, no party would incur liabilities that exceed a fixed percentage of the actual revenue amounts in the aggregate that it will have collected under the Agreement up to the date of the particular claim or suit. Thus, the 7.5% would be applied to the amount paid or payable by the party on the day the claim arose, with amounts yet to be billed excluded from the calculation. If, for example, BellSouth's negligence caused liability on the first day of the Agreement, BellSouth's liability would be zero even if the liability were not discovered until the last day of the Agreement. Conversely, if the event occurred at the end of the Agreement, the liability would be considerably greater.

The Joint Petitioners' central argument was that BellSouth's proposal would not make the Joint Petitioners whole when a wrong occurs. A breach in performance affects a carrier's customer relationships with losses greater than mere wholesale cost. The Joint Petitioners also maintained that their proposal does not seek to expose BellSouth to risk outside of the general commercial liability coverage afforded by the typical insurance policy. The Joint Petitioners argued that their approach is commercially reasonable.

BellSouth replied that the Joint Petitioners' proposal is flawed because it irrationally limits – or expands – damages based on the point in time that the event occurs. BellSouth also argued that the Joint Petitioners were attempting to shift financial responsibility for their business decisions to BellSouth. Interconnection agreements are not commercial agreements but are governed by different standards. In addition, BellSouth also pointed out on cross-examination that KMC, NuVox, and NewSouth all admitted that they limited their liability to customers to service credits.

The Commission finds that BellSouth's language is more appropriate. The FCC's *Virginia Arbitration Order* (July 17, 2002) reviewed a similar issue in an arbitration between Verizon Virginia, Inc. (Verizon) and WorldCom, Inc. (WorldCom). There, the FCC concluded that it was appropriate for Verizon to treat WorldCom in the same manner as it treats its own customers. The FCC noted that Verizon has no duty to provide perfect service to its own customers, and it was unreasonable to place that duty on Verizon with respect to WorldCom. The FCC further observed that Verizon has no contractual relationship with WorldCom's customers, and it cannot therefore limit its liability with respect to them as it may with its own customers.

While the Commission believes that the parties may certainly negotiate a liability "cap" themselves, it would be imprudent to impose one on the parties in arbitration, especially where, as in this case, the amount of damages is related to the *timing* of the event rather than the event itself.

CONCLUSIONS

The Commission concludes that BellSouth's proposed language providing that liability with respect to this issue should be limited to service credits should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

ISSUE NO. 3 – MATRIX ITEM NO. 5:

Joint Petitioners' Issue Statement: Should each party be required to include specific liability-eliminating terms in all its tariffs and end user contracts (past, present, and future) and to the extent that a Party does not or is unable to do so, should it be obligated to indemnity the other Party?

BellSouth's Issue Statement: If the CLP elects not to place in its contracts with end users and/or tariff standard industry limitations of liability, who should bear the risks that result from this business decision?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners argued that they cannot limit BellSouth's liability in contractual arrangements where BellSouth is not a party. Moreover, the Joint Petitioners asserted that they will not indemnify BellSouth in any suit based on BellSouth's failure to perform its obligations under this contract or to abide by applicable law. BellSouth should not be able to dictate the terms of service between the Joint Petitioners and their customers by, among other things, holding the Joint Petitioners liable for failing to mirror BellSouth's limitation of liability and indemnification provisions in the CLP's End User tariffs and/or contracts. To the extent that a Party does not, or is unable to, include specific elimination-of-liability terms in all of its tariffs and End User contracts (past, present, and future), and provided that the non-inclusion of such terms is commercially reasonable, in the particular circumstances, that Party should not be required to indemnify and reimburse the other Party for that portion of the loss that would have been limited had the first Party included in its tariffs and contracts the elimination-of-liability terms that such other Party was successful in including in its tariffs at the time of such loss.

BELLSOUTH: To the extent the Joint Petitioners decide not to limit their liability in accordance with industry standards, the Joint Petitioners should indemnify BellSouth for any loss BellSouth sustains as a result of that decision. BellSouth noted that the exact language it is proposing for this issue is in the Joint Petitioners' current agreement and has never been the subject of a dispute. In addition, the Joint Petitioners have limitation of liability language in their tariffs and contracts which are in force today. BellSouth's proposal is not a limitation of a right of third parties via this contract but rather imposes obligations upon the Joint Petitioners in the event they make a business decision not to limit their liability within industry standards. BellSouth should not be exposed to greater liability than otherwise contemplated simply because the end user is a CLP.

PUBLIC STAFF: The Public Staff agreed with BellSouth that, if a CLP elects not to limit its liability to its end users/customers in accordance with industry norms, the CLP should bear the risk of loss arising from its business decision.

DISCUSSION

The fundamental issue here concerns whether BellSouth can require the Joint Petitioners' to indemnify it if they do not limit their liability to their customers in their own tariffs and contracts and BellSouth suffers a loss as a result. BellSouth says "yes" and the Joint Petitioners say "no."

The gist of the Joint Petitioners' argument was that they cannot limit BellSouth's liability in contracts to which BellSouth is not a party and that BellSouth's language inhibits their ability to compete by reducing their ability to relax limitations on liability in order to contract with customers.

BellSouth replied that their language is not aimed at third-party contracts but at the contract between itself and the Joint Petitioners by requiring the Joint Petitioners to bear the risk of their business decisions. BellSouth argued that under the Joint Petitioners' proposal, the CLPs could promise their customers perfection and then hold BellSouth financially accountable when it does not deliver. BellSouth is only required to provide service to CLPs at parity to that it provides its own retail customers.

The Public Staff expressed concerns about the rights of consumers and about the BellSouth language allowing parties to limit their liability to end users and third parties for any loss, tort or contract, but stated that its concerns were allayed because the BellSouth language does not dictate the terms of the agreements between CLPs and customers but provides them the discretion to include such limitation of liability. The Public Staff noted that the Joint Petitioners have limitation of liability language in their own tariffs and contracts and that the current agreements contain the limitation on liability contained here. There is no evidence the proposed language has caused a dispute or adversely affected a third party or that the CLPs have in fact relaxed their limitation of liability language to attract customers.

The Commission believes that the arguments advanced by BellSouth and the Public Staff are more persuasive for the reasons as generally stated by them, and the BellSouth contract language should therefore be adopted.

CONCLUSIONS

The Commission concludes that if a party elects not to place standard industry limitations of liability in its contracts with end users or in its tariffs, that party shall indemnify the other party for any loss resulting from this decision. Accordingly, BellSouth's proposed language in the Agreement, in the General Terms and Conditions, Section 10.4.2 should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 AND 5

ISSUE NOS. 4 AND 5 – MATRIX ITEM NO. 6:

Joint Petitioners' Issue Statement: Should limitation or liability for indirect, incidental, or consequential damages be construed to preclude liability for claims or suits for damages incurred by CLP's (or BellSouth's) end-users to the extent such damages result directly and in a reasonably foreseeable manner from BellSouth's (or CLP's) performance obligations set forth in the Agreement?

BellSouth's Issue Statement: How should indirect, incidental, or consequential damages be defined for purposes of the Agreement?

POSITIONS OF PARTIES

JOINT PETITIONERS: The limitation of liability terms in the Agreement should not preclude damages that CLPs' End Users incur as a foreseeable result of BellSouth's performance of its obligations, including its provisioning of UNEs and other services. Damages to End Users that result directly, proximately, and in a reasonably foreseeable manner from BellSouth's (or a CLP's) performance of obligations set forth in the Agreement that were not otherwise caused by, or are the result of, a CLP's (or BellSouth's) failure to act at all relevant times in a commercially reasonable manner in compliance with such Party's duties of mitigation with respect to such damage should be considered direct and compensable under the Agreement for simple negligence or nonperformance purposes.

BELLSOUTH: Parties should not be responsible or liable for indirect, incidental, or consequential damages except in cases of gross negligence or willful or intentional misconduct.

PUBLIC STAFF: The Public Staff agreed with BellSouth's position.

DISCUSSION

In support of their proposed provision on this issue, the Joint Petitioners explained that in any contract, each party should be liable for damages that are the direct and foreseeable result of its actions. This liability is appropriately borne by any service provider in a contract that envisions that the effect of such services will be passed on to ascertainable third parties related to the other party to the contract. Since this Agreement is a wholesale agreement, liability for injury to third parties must be covered by express language.

The Joint Petitioners claimed that BellSouth's proposed language is ambiguous. While BellSouth asserts that, "[e]xcept in cases of gross negligence or willful or intentional misconduct, under no circumstances shall a Party be responsible or liable for indirect, incidental, or consequential damages[,]" other provisions of the Agreement provide disclaimers of liability to end users predicted on specified circumstances. The Joint Petitioners wanted the Agreement to ensure that their end users' rights against BellSouth are not limited in any way. On cross-examination, however, the Joint Petitioners conceded that, pursuant to general contract law, the Agreement could not impact the rights of their end users and offered to delete their proposal on this issue from the Agreement, if BellSouth removes its proposal as well.

BellSouth maintained that indirect, incidental, and consequential damages should be defined according to state law. While the Joint Petitioners agreed that the contract should provide no liability for these types of damages, the Joint Petitioners then tried to include a "lengthy and confusing" set of circumstances where liability would attach, even if these damages are actually indirect, incidental, or consequential, thereby eviscerating the agreed-upon limitation of liability. In sum, BellSouth sought to exclude these damages completely, as defined by state law, without exception. Since case law defines these damages, there is no need to further negotiate. BellSouth further objected to the "qualifying" language proposed by the Joint Petitioners because it is extremely vague and unnecessary since the contract cannot extend rights to third parties.

The Public Staff concurred in BellSouth's position.

The Commission approves BellSouth's proposed version of Section 10.4.4 in the General Terms and Conditions of the Agreement. The Commission agrees that the language proposed by the Joint Petitioners is unnecessary and potentially confusing. The end users are not parties to this Agreement or arbitration and therefore their rights should be defined not by this Agreement, but rather pursuant to state contract law. As the Joint Petitioners themselves concede, this language cannot be used to extend the rights of their customers. As such, the Joint Petitioners' proposed language is superfluous and should be removed from the contract to avoid confusion. Furthermore, indirect, incidental, or consequential damages should be defined by state law.

CONCLUSIONS

The Commission concludes that the rights of end users should be defined pursuant to state contract law. The Commission further concludes that incidental, indirect, and consequential damages should be defined pursuant to state law. Therefore, the Commission believes BellSouth's proposed language for Section 10.4.4 should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

ISSUE NO. 6 – MATRIX ITEM NO. 7: What should the indemnification obligations of the Parties be under this agreement?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Party providing service under the Agreement should be indemnified, defended, and held harmless by the Party receiving services against any claim for libel, slander, or invasion of privacy arising from the content of the receiving Party's own communications. Additionally, customary provisions should be included to specify that the Party receiving services under the Agreement should be indemnified, defended, and held harmless by the Party providing services against any claims, loss, or damage to the extent reasonably arising from: (1) the providing Party's failure to abide by applicable law, or (2) injuries or damages arising out of or in connection with this Agreement to the extent caused by the providing Party's negligence, gross negligence, or willful misconduct.

BELLSOUTH: Indemnification of the providing Party should be limited to two situations: (1) claims for libel, slander, or invasion of privacy arising from the content of the Party's own communications; or (2) any claim, loss, or damages claims by the "End User or customer of the Party receiving services arising from such company's use or reliance on the providing Party's services, actions, duties, or obligations arising out of this Agreement." Thus, BellSouth's language is narrower and insures that the providing Party will be indemnified in the unique situation when the end user of the receiving Party sues the providing Party based on the receiving Party's use or reliance of services provided by the providing Party. BellSouth noted that in most cases the Joint Petitioners will be the receiving party and BellSouth will be the providing party.

PUBLIC STAFF: The Public Staff supported Joint Petitioners' proposed language.

DISCUSSION

While the parties agree that the receiving party should be indemnified for claims of libel, slander, or invasion of privacy, the Joint Petitioners contended that the providing party should undertake a heavier indemnity obligation, including reasonable and proximate losses to the extent it becomes liable due to the other party's negligence, gross negligence, willful misconduct, or failure to abide by applicable law. Their language would ensure that each party will be indemnified to a third-party in the case the other party's failure to comply with applicable law, regardless of whether the party is receiving or providing service. The Joint Petitioners objected to BellSouth's proposal because it provides that only the party providing services is indemnified under the Agreement.

BellSouth contended that the Joint Petitioners go too far in contending that the party receiving services should be indemnified, defended, and held harmless by the party providing services against claims, losses, and damages. BellSouth also contended that an interconnection agreement is not a commercial agreement but is rather governed by the Act and subsequent arbitration. Services provided pursuant to Section 251 are priced according to TELRIC principles and do not include open-ended indemnification of the party receiving services. TELRIC pricing does not account for the level of risk BellSouth is being asked to assume. If the Joint Petitioners would limit their liability to their customers through their tariffs or contracts, there would be no issue here.

The Public Staff concurred in the Joint Petitioners' position.

The Commission notes that in Finding of Fact No. 3 above, the Commission approved BellSouth's proposal for Section 10.4.2. This proposal allows the Joint Petitioners to limit their liability to customers through their tariffs or contracts and protects BellSouth if they do not. This limitation of liability provision appears to remove BellSouth's objection to the Joint Petitioners' proposal. Without that objection, there appears to be no issue.

CONCLUSIONS

The Commission concludes that the Joint Petitioners' proposed language for Section 10.5 in the General Terms and Conditions of the Agreement should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

ISSUE NO. 7 – MATRIX ITEM NO. 9:

Joint Petitioners' Issue Statement: Should a court of law be included among the venues at which a Party may seek dispute resolution under the Agreement?

BellSouth's Issue Statement: Should a party be allowed to take a dispute concerning the interpretation or implementation of any provision of the Agreement to a court of law for resolution without first exhausting administrative remedies?

POSITIONS OF PARTIES

JOINT PETITIONERS: Either party should be able to petition the Commission, the FCC, or a court of law for a resolution of a dispute. No legitimate dispute resolution should be foreclosed to the parties. The industry has experienced difficulties in achieving efficient regional dispute resolution. Moreover, there is an ongoing debate as to whether state commissions have the jurisdiction to enforce agreements and as to whether the FCC will engage in such enforcement. Courts of law have the jurisdiction to entertain such disputes. Indeed, in certain circumstances, they may be better equipped to adjudicate disputes and may provide a more efficient alternative to litigating before up to nine different state commissions or to waiting for the FCC to decide whether it will or will not accept an enforcement role given the particular facts.

BELLSOUTH: The Commission or the FCC should initially resolve disputes as to the appropriate interpretation and implementation of the Agreement. There can be no question that the Commission should resolve matters that are within its expertise and jurisdiction. State commissions are in the best position to resolve disputes relating to the interpretation or enforcement of agreements it approves. The Eleventh Circuit has recognized this, noting that the power to approve or reject interconnection agreements implies the power to interpret and enforce those agreements in the first instance. The Joint Petitioners actually conceded that the state commissions have the authority to enforce and interpret interconnection agreements but they seek the ability to go to a single forum, such as a court, to address region-wide disputes and avoid bifurcated hearings. But bifurcated hearings may be unavoidable if, under the doctrine of primary jurisdiction, a court would resolve matters outside of the expertise of the state commissions, while the nine state commissions would resolve matters within their expertise. BellSouth's language gives the Joint Petitioners the ability to resolve a dispute in a single forum—namely, the FCC.

PUBLIC STAFF: The Public Staff supported the Joint Petitioners' language.

DISCUSSION

The nub of this issue is whether the parties should be allowed to seek resolution of disputes regarding their Agreement in courts of law before first seeking resolution before the Commission. The Joint Petitioners noted that their present agreements have such a provision and argued that it is unclear that the Commission may issue an Order approving agreement language which deprives a court of jurisdiction, since the subject matter of state courts is set by the Legislature and that of the federal courts is set by Congress. BellSouth indicated that it would only permit disputes to be adjudicated in a court of law for matters lying outside the jurisdiction of the FCC or the Commission.

The Public Staff was cautious about whether the Commission had the authority to issue an order approving agreement language which would, over the objections of a party, deprive a court of its jurisdiction.

The Commission shares the concerns of the Joint Petitioners and the Public Staff on this issue. The subject matter of the North Carolina courts is set by the Legislature pursuant to N.C. Constitution Art. IV, Sec. 1 and of the federal courts by Congress pursuant to U.S. Constitution, Art. III, Sec. 1. It would thus appear questionable whether the Commission could approve an agreement depriving either set of courts of their jurisdiction to hear claims from parties seeking dispute resolution. Whether a court of law has jurisdiction over any particular claim is a matter to be adjudicated by the petitioned tribunal, and this need not be determined at this point.

CONCLUSIONS

The Commission concludes that the language proposed by the Joint Petitioners for Section 13 in the General Terms and Conditions of the Agreement should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

ISSUE NO. 8 – MATRIX ITEM NO. 12: Should the Agreement explicitly state that all existing state and federal laws, rules, regulations, and decisions apply unless otherwise specifically agreed to by the parties?

POSITIONS OF PARTIES

JOINT PETITIONERS: Nothing in the Agreement should be construed to limit a party's rights or exempt a party from obligations under applicable law, as defined in the Agreement,[1] except in such cases where the parties have explicitly agreed to a limitation or exemption. Moreover, silence with respect to any issue, no matter how discrete, should be construed to be such a limitation or exception. This is a basic legal tenet and is consistent with both federal and Georgia law (agreed to by the parties), and it should be explicitly stated in the Agreement in order to avoid unnecessary disputes and litigation that has plagued the parties in the past.

[1] Section 32.1 defines "Applicable Law" as "all applicable federal, state, and local statutes, laws, rules regulations, codes, effective orders, injunctions, judgments and binding decisions and decrees that relate to the obligations under this Agreement."

BELLSOUTH: BellSouth characterized the issue as being how the parties should handle disputes when one party asserts that an obligation, right, or other requirement arising from telecommunications law is applicable even if it is not expressly memorialized in the Agreement. The issue is not whether BellSouth intends to comply with applicable law; it has. The issue is about providing certainty in the Agreement as to the parties' obligations.

PUBLIC STAFF: The Public Staff supported Joint Petitioners' proposed language.

DISCUSSION

Essentially, the Joint Petitioners have argued that the Agreement should state that a party's rights and obligations under all relevant law existing at the time of the contract should apply unless explicitly limited or exempted. In this Agreement, the relevant state law would be Georgia law. The Joint Petitioners contended that an express provision that existing law applies unless expressly excluded or exempted would reduce disputes and litigation between the parties.

The text of the Joint Petitioners' proposal is as follows: "*Nothing in this Agreement shall be construed to limit a Party's rights or exempt a Party from obligations under Applicable Law, except in such cases where the Parties have explicitly agreed to an exception to a requirement of Applicable law or to abide by the provisions which conflict with and thereby displace corresponding requirements of Applicable Law. Silence shall not be construed to be such an exemption to or displacement of any aspect, no matter how discrete, of Applicable Law.*"

BellSouth contended that the Joint Petitioners' position would create more uncertainty, and it believes that, if there is a disagreement over applicable law, after the dispute is resolved, the Agreement should be amended so that the new obligation applies only prospectively and not retroactively.

The text of BellSouth's proposal is as follows: "*This Agreement is intended to memorialize the Parties' mutual agreement with respect to their obligations under the Act and applicable FCC and Commission rules and orders. To the extent that either Party asserts that an obligation, right, or other requirement, not expressly memorialized herein, is applicable under this agreement by virtue of a reference to an FCC or Commission rule or order or, with respect to substantive Telecommunications law only, Applicable Law, and such obligation, right, or other requirement is disputed by the other Party, the Party asserting such obligation, right, or other requirement is applicable shall petition the Commission for resolution of the dispute and the Parties agree that any finding by the Commission that such obligation, right or other requirement exists shall be applied prospectively by the Parties upon amendment of the Agreement to include such obligation, right, or other requirement and any necessary rates, terms, and conditions, and the Party that failed to perform such obligation, right, or other requirement shall be held harmless from any liability for such failure until the obligation, right, or other requirement is expressly included in this Agreement by amendment thereto.*"

The Public Staff was supportive of the Joint Petitioners' language, believing that it would help to avoid controversies in the future. While it is unclear as to whether silence regarding the applicable law indicates that such law either does or does not apply, the Public Staff believes the Agreement should specifically address this matter to avoid potential litigation. The Public Staff further noted that BellSouth's proposed language allowing a party to seek Commission resolution if a disagreement arises over whether an applicable law, rule, or order applies to the Agreement and providing that the Commission's decision applies prospectively, does not resolve the question of silence in the Agreement. The Public Staff criticized the fairness of BellSouth's view of applying the law prospectively, since this would give an incentive to adopt an extreme or untenable interpretation of applicable law and then allow the party adopting that view to escape fiscal responsibility for the delay it caused by necessitating litigation before the Commission over its proper interpretation.

The Commission believes that the language proposed by the parties is in both cases problematical. The purpose of a contract is to memorialize the parties' mutual agreement at a particular point in time for the term of the contract, and the general purpose of the typical applicable law provision in a contract is to ensure that the parties do not break the law. Thus, the specific terms of the contract are to have primary significance. If there are particular laws that the parties wish to provide terms, but which they do not want to rewrite or negotiate, these specific laws should be incorporated by reference.

The principal defect of the Joint Petitioners' language is that it purports to import the entirety of "Applicable Law," except where the parties have agreed otherwise. Silence as to that law is, so to speak, no defense. This amounts to a "roving expedition" for a party to seek out other law, "no matter how discrete," to supply terms for the Agreement. The Commission believes this goes too far and is out of harmony with what a standard applicable law provision is supposed to do.

The principal defect of BellSouth's language is that it inserts a "prospectivity" clause which, as the Public Staff points out, gives an incentive to extreme positions and posturing. "Prospectivity" is also out of harmony with what a standard applicable law provision is supposed to do. In any case, should the Commission interpret the parties' intent and the meaning of certain contractual provisions, the law generally holds that the Commission's interpretation should be applicable during the entire term of the contract unless there was language directly to the contrary.

Nevertheless, the BellSouth language is more susceptible to reform. BellSouth is on firmer ground when it states that the "Agreement is intended to memorialize the Parties' mutual agreement" and provides that, "where something is not expressly memorialized but is nevertheless argued to be applicable, the matter should be referred to the Commission for resolution." This language should in large measure be retained up to the point of the phrase "resolution of the dispute," with some modifications for greater clarity, and the balance of the language, which deals with "prospectivity" should be deleted. References to courts of law and the FCC should be added to be consistent with the decision in the Evidence and Conclusions for Finding of Fact No. 7 above.

The Commission is doubtful that any language can be framed that anticipates all possible disputes given the volume of laws, legal principles, and possible fact situations involved. If both parties dislike the language suggested by the Commission, they are free to negotiate something which seems better to them.

CONCLUSIONS

The Commission concludes that the BellSouth language should be adopted as modified to read: "*This Agreement is intended to memorialize the Parties' mutual agreement with respect to their obligations under the Act and applicable FCC and Commission rules and orders. To the extent that either Party asserts that an obligation, right, or other requirement, not expressly memorialized herein, is applicable under this Agreement by virtue of an FCC or Commission rule or order or, with respect to Applicable Law relating to substantive Telecommunications law only, and such obligation, right, or other requirement is disputed by the other Party, the Party asserting such obligation, right, or other requirement is applicable shall petition the Commission, a court of law, or the FCC for resolution of the dispute.*"

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

ISSUE NO. 9 - MATRIX ITEM NO. 26: Should BellSouth be required to commingle UNEs or combinations with any service, network element or other offering that it is obligated to make available pursuant to Section 271 of the Act?

POSITIONS OF PARTIES

JOINT PETITIONERS: Yes. BellSouth should be required to commingle UNEs or combinations with any service, network element, or other offering that it is obligated to make available pursuant to Section 271 of the Act.

BELLSOUTH: BellSouth argued that this matter should be moved to the change of law docket for consideration and resolution because similar if not identical issues are being raised in the change of law proceeding. At a minimum the Commission should defer resolution of this item until its decision in the change of law docket to avoid inconsistent rulings. Otherwise, BellSouth's view is that consistent with the FCC's *Errata* to the *TRO*, there is no requirement to commingle UNEs or combinations with services, network elements or other offerings made available only under Section 271 of the Act.

PUBLIC STAFF: The Public Staff recommended that the Commission conclude that 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. This includes wholesale services obtained from any method, including those obtained as Section 271 elements.

DISCUSSION

The Commission notes that this issue involves whether BellSouth is required to commingle UNEs or combinations of UNEs with any service, network element, or other offering that it is obligated to make available pursuant to Section 271 of the Act.

The Joint Petitioners noted that the FCC specifically eliminated the temporary commingling restrictions that it had adopted on stand-alone loops and EELs and clarified that BellSouth is required to perform the necessary functions to effectuate such commingling in the

TRO. Next, the Joint Petitioners contended that the FCC has concluded that Section 271 requires BellSouth to provide network elements, services and other offerings and that such elements are not provided pursuant to the unbundling requirements of Section 251. Therefore, the Joint Petitioners opined that the FCC rules require BellSouth to commingle a UNE or a UNE combination with any facilities or services that they may obtain at wholesale, pursuant to Section 271, from BellSouth.

BellSouth interpreted the FCC's decisions differently, and argued that pursuant to the *Errata* to the *TRO*, it is not required to commingle UNEs or UNE combinations with services, network elements or other offerings made available only pursuant to Section 271. Unbundling and commingling are Section 251 obligations, so that when BellSouth provides an item pursuant to Section 271 only, BellSouth argued that it is not required to combine or commingle that item with any other element or service. However, BellSouth commented that it may agree to do so in a commercial agreement. BellSouth further contended that the *USTA II* decision is consistent with the FCC's decision finding no requirement to commingle UNEs or UNE combinations with services, network elements or offerings made available pursuant to Section 271.

BellSouth acknowledged that it does occasionally provide some Section 271 elements as wholesale services. For example, retail customers may buy certain Section 271 transport elements through BellSouth's special access tariff. However, BellSouth contended that switching is neither a wholesale service nor a retail service; it is a Section 271 obligation only. BellSouth agreed to commingle UNEs with tariffed services or resold services and it would commingle a Section 271 transport element. BellSouth maintained that it will not, however, commingle switching because it does not provide switching as a wholesale service.

The Public Staff explained that the FCC has defined commingling in Rule 51.5 to mean the connecting, attaching, or otherwise linking of an unbundled network element, or a combination of unbundled network elements, to one or more facilities or services that a requesting telecommunications carrier has obtained at wholesale from an incumbent LEC, or the combining of an unbundled network element, or a combination of unbundled network elements, with one or more such facilities or services. The Public Staff noted that, furthermore, Paragraph 579 of the *TRO* states that an ILEC shall permit a CLP to commingle 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 a method other than unbundling under Section 251(c)(3). Thus, the Public Staff claimed that resolution of this issue depends on whether Section 271 elements, local switching in particular, are wholesale services.

The Public Staff believed that BellSouth's arguments that Section 271 elements are not wholesale services do not stand up to scrutiny. The Public Staff stated that *Black's Law Dictionary* defines wholesale as "[s]elling to resellers and jobbers rather than to consumers. A sale in large quantity to one who intends to resell."[1] The Public Staff commented that Section 271 elements purchased by CLPs are used in the provision of service to others, namely end users. The Public Staff further commented, that is, CLPs are reselling the Section 271 elements obtained from BellSouth to provide a telecommunications service.

The Public Staff stated that its interpretation of the *TRO* and FCC Rule 51.5 reveals that the term wholesale is not limited to services offered by an ILEC through its tariffs. The Public

[1] Black's Law Dictionary 823 (5th ed. 1983).

Staff stated that Rule 51.5 simply requires that the telecommunications carrier obtain the service at wholesale. The Public Staff further stated that, while services obtained through tariffs are used as an example, the language does not suggest that this is the only type of wholesale service that ILECs must commingle. The Public Staff believed that the only limitation to commingling is that the service must be obtained at wholesale in a manner other than through the unbundling provisions of Section 251(c)(3) of the Act. The Public Staff suggested that since Section 271 elements are obtained in a manner other than through the provisions of Section 251(c)(3), Section 271 elements qualify as wholesale services subject to the commingling requirements of the FCC.

The Commission notes that in Paragraph 579 of the *TRO*, in which the FCC eliminates the commingling restriction applied to stand-alone loops and EELs, the FCC repeatedly references "*switched and special access services offered pursuant to tariff*" when using the term wholesale services. In describing wholesale services that are subject to commingling, the FCC refers to tariffed access services.[1] While the FCC references services obtained through tariffs as an example of wholesale services that ILECs must commingle, the FCC does not expressly define "wholesale services" in the context of the commingling obligation.

In Paragraph 579 of the *TRO*, the FCC has defined commingling as:

> By commingling, we mean the connecting, attaching, or otherwise linking of a UNE, or a UNE combination, to one or more facilities or services that a requesting carrier has obtained at wholesale from an incumbent LEC pursuant to any method other than unbundling under Section 251(c)(3) of the Act, or the combining of a UNE or UNE combination with one or more such wholesale services.

Further, in the Section 271 Issues section of the *TRO*, the FCC states:

> We decline to require BOCs, pursuant to Section 271, to combine network elements that no longer are required to be unbundled under Section 251. Unlike Section 251(c)(3), items 4-6, and 10 of Section 271's competitive checklist contain no mention of "combining" and ... do not refer back to the combination requirement set forth in Section 251(c)(3).

The Commission believes that the foregoing shows that the FCC did not intend for ILECs to commingle Section 271 elements with Section 251 elements. After careful consideration, the Commission finds that there is no requirement to commingle UNEs or combinations with services, network elements or other offerings made available only under Section 271 of the Act.

CONCLUSIONS

The Commission concludes that 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. However, this does not include services, network elements or other offerings made available only under Section 271 of the Act.

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[1] *TRO*, ¶¶ 579 – 581, 583.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

ISSUE NO. 10 - MATRIX ITEM NO. 36: How should line conditioning be defined in the Agreement; and what should BellSouth's obligations be with respect to line conditioning?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners asserted that line conditioning should be defined in the Agreement as set forth in FCC Rule 51.319(a)(1)(iii)(A); and BellSouth should perform line conditioning in accordance with FCC Rule 51.319(a)(1)(iii).

BELLSOUTH: BellSouth maintained that line conditioning should be defined as a routine network modification that BellSouth regularly undertakes to provide digital subscriber line (xDSL) services to its own customers; and BellSouth's line conditioning obligations should be limited to what BellSouth routinely provides for its own customers.

PUBLIC STAFF: The Public Staff agreed with the Joint Petitioners' position.

DISCUSSION

According to the Joint Petitioners' Petition for Arbitration and the Joint Petitioners' Exhibit A, this issue relates to the matter of the appropriate contract language to be included in Section 2.12.1 of Attachment 2 (Network Elements and Other Services) to the Agreement.

The Joint Petitioners asserted that the term, line conditioning, should be defined in the Agreement as set forth in FCC Rule 51.319(a)(1)(iii)(A). That paragraph of the Rule states:

> Line conditioning is defined as the removal from a copper loop or copper subloop of any device that could diminish the capability of the loop or subloop to deliver high-speed switched wireline telecommunications capability, including digital subscriber line service. Such devices include, but are not limited to, bridge taps, load coils, low pass filters, and range extenders.

The Joint Petitioners also contended that BellSouth should perform line conditioning in accordance with FCC Rule 51.319(a)(1)(iii). That paragraph of the Rule states:

> <u>Line conditioning</u>. The incumbent LEC shall condition a copper loop at the request of the carrier seeking access to a copper loop under paragraph (a)(1) of this section, the high frequency portion of a copper loop under paragraph (a)(1)(i) of this section, or a copper subloop under paragraph (b) of this section to ensure that the copper loop or copper subloop is suitable for providing digital subscriber line services, including those provided over the high frequency portion of the copper loop or copper subloop, whether or not the incumbent LEC offers advanced services to the end-user customer on that copper loop or copper subloop. If the incumbent LEC seeks compensation from the requesting telecommunications carrier for line conditioning, the requesting telecommunications carrier has the option of refusing, in whole or in part, to have

> the line conditioned; and a requesting telecommunications carrier's refusal of some or all aspects of line conditioning will not diminish any right it may have, under paragraphs (a) and (b) of this section, to access the copper loop, the high frequency portion of the copper loop, or the copper subloop.

BellSouth argued that line conditioning should be defined as a routine network modification that BellSouth regularly undertakes to provide xDSL services to its own customers. BellSouth contended that its line conditioning obligations should be limited to what BellSouth routinely provides for its own customers.

The specific language proposed to be included in the Agreement in Attachment 2, Section 2.12.1 is as follows, with the differences between the Joint Petitioners' proposal and BellSouth's proposal being denoted with underlined text:

Joint Petitioners' Version –

> <u>BellSouth shall perform line conditioning in accordance with FCC 47 C.F.R. 51.319(a)(1)(iii). Line Conditioning is as defined in FCC 47 C.F.R. 51.319(a)(1)(iii)(A).</u> Insofar as it is technically feasible, BellSouth shall test and report troubles for all the features, functions, and capabilities of conditioned copper lines, and may not restrict its testing to voice transmission only.

BellSouth's Version –

> <u>Line Conditioning is defined as a RNM [Routine Network Modification] that BellSouth regularly undertakes to provide xDSL services to its own customers. This may include the removal of any device, from a copper loop or copper sub-loop that may diminish the capability of the loop or sub-loop to deliver high-speed switched wireline telecommunications capability, including xDSL service. Such devices include, but are not limited to; load coils, low pass filters, and range extenders.</u> Insofar as it is technically feasible, BellSouth shall test and report troubles for all the features, functions, and capabilities of conditioned copper lines, and may not restrict its testing to voice transmission only.

In their Proposed Order, the Joint Petitioners stated that line conditioning is a Section 251(c)(3) obligation of the ILECs. The Joint Petitioners observed that in its *UNE Remand Order*[1], the FCC clarified its unbundling rules to require that ILECs condition copper loops to provide advanced services; and FCC Rule 51.319(a)(3)[2] was promulgated with the *UNE*

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[1] FCC 99-238, CC Docket No. 96-98, released on November 5, 1999.

[2] In the *UNE Remand Order*, the FCC's Rule 51.319(a)(3), including subsections, was worded as follows:

> Line conditioning. The incumbent LEC shall condition lines required to be unbundled under this section wherever a competitor requests, whether or not the incumbent LEC offers advanced services to the end-user customer on that loop.
> (A) Line conditioning is defined as the removal from the loop of any devices that may diminish the capability of the loop to deliver high-speed switched

Remand Order to effect the clarification stated in the Order. Further, the Joint Petitioners pointed out that pursuant to that rule, the Commission addressed the issues surrounding line conditioning in its *Recommended Order Concerning all Phase I and Phase II Issues Excluding Geographic Deaveraging*, issued June 7, 2001, in Docket No. P-100, Sub 133d. The Joint Petitioners noted that in that docket, the Commission established rates for removing load coils on loops less than 18,000 feet and for loops 18,000 feet and greater; and it established rates for bridged tap removal. The Joint Petitioners commented that, thereafter, BellSouth signed interconnection agreements incorporating these services at rates prescribed by the Commission.

Further, the Joint Petitioners maintained that they found no basis for BellSouth's position that its line conditioning obligations were changed by the FCC's *TRO*, as the line conditioning rules were readopted in the *TRO*. The Joint Petitioners pointed out that even BellSouth witness Fogle conceded on cross-examination, that the FCC's definition of line conditioning in the *TRO* was virtually identical to the definition in the *UNE Remand Order*. The Joint Petitioners also observed that they found it persuasive that there is no mention in the line conditioning rules of the routine network modification rules, much less a limitation on the former by the latter.

In addition, the Joint Petitioners argued that BellSouth's reliance on a single sentence in the *TRO*, at Paragraph 643 is misplaced. That sentence reads as follows: "Instead, line conditioning is properly seen as a routine network modification that incumbent LECs regularly perform in order to provide xDSL services to their own customers." The Joint Petitioners asserted that there is no conflict between the subject sentence in Paragraph 643 and the routine network modification rules on the one hand and the line conditioning rules on the other hand.

Furthermore, the Joint Petitioners commented that KMC witness Johnson explained the relationship between the two sets of rules. In particular, witness Johnson stated that the way to reconcile the second sentence in Paragraph 643 of the *TRO* and the rule from the *TRO*, is to recognize that there is an intersection between two separate and distinct functions. Witness Johnson testified that the first function is line conditioning and even in the *TRO*, in Footnote 1947, the FCC recognized that conditioning is an obligation to cover loops of any length, to recognize the potential degradation of analog voice service, and to enable ILECs to charge for conditioning loops. As a point of further clarification, witness Johnson stated that the FCC provided two distinct definitions – one for line conditioning, which is set forth in Part iii, Letter A of the Rule, and then the second for routine network modifications. Witness Johnson remarked that the FCC recognized that there may be some subset of line conditioning activities that are routine network modifications. Witness Johnson stated that the subject sentence in Paragraph 643 references one type of line conditioning function known as routine network

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wireline telecommunications capability, including xDSL service. Such devices include, but are not limited to, bridge taps, low pass filters, and range extenders.

(B) Incumbent LECs shall recover the cost of line conditioning from the requesting telecommunications carrier in accordance with the Commission's forward-looking pricing principles promulgated pursuant to section 252(d)(1) of the Act.

(C) Incumbent LECs shall recover the cost of line conditioning from the requesting telecommunications carrier in compliance with rules governing nonrecurring costs in § 51.507(e).

(D) In so far as it is technically feasible, the incumbent LEC shall test and report trouble for all the features, functions, and capabilities of conditioned lines, and may not restrict testing to voice-transmission only.

modifications. Witness Johnson contended that the definition set forth by the FCC in its line conditioning rule is what the FCC intended the definition to be, which is "Line conditioning is defined as the removal from a copper loop or copper subloop of any device that could diminish the capability of the loop or subloop to deliver high-speed switched wireline telecommunications capability, including digital subscriber line service. Such devices include, but are not limited to, bridge taps, load coils, low pass filters, and range extenders." In addition, witness Johnson testified that "[i]t's important to note that the line conditioning definition focuses on the removal of these types of gadgets and equipment from lines. Whereas, if you look at the routine network modifications definition, it focuses on the addition of whatever devices are required in order to make sure that the quality of the line functions. So, I believe that the FCC intended and clearly set forth two separate and distinct functions line conditioning and routine network modifications, and [Paragraph] 643 just references one type of line conditioning." Further, witness Johnson illustrated her position with a Venn diagram which was identified as Joint Petitioners Redirect Exhibit 1, which showed two intersecting circles, with the intersection of the circles representing those activities common to both definitions.

The Joint Petitioners contended that under BellSouth's interpretation, the exception would swallow the rule. The Joint Petitioners remarked that on questioning by Commissioner Kerr, BellSouth witness Fogle conceded that BellSouth's conditioning obligations would be entirely dependent upon BellSouth's sole discretion as to what activities were or were not routine for BellSouth. The Joint Petitioners opined that they did not believe the FCC had any such intention, when it adopted its line conditioning and routine network modification rules, since such a result would effectively eliminate line conditioning.

In its Brief, BellSouth maintained that for the same reasons as discussed in its comments for Matrix Item No. 26, the Commission should move Matrix Item No. 36 to the change of law docket (Docket No. P-55, Sub 1549) for consideration and resolution because similar if not identical issues are being raised in the change of law proceeding. At a minimum, BellSouth asserted that the Commission should defer resolution of this item until its decision in the change of law proceeding to avoid inconsistent rulings.

However, in the event the Commission chooses to address this issue now, BellSouth argued that the Joint Petitioners' position should be rejected because it conflicts with the *TRO* and BellSouth's nondiscriminatory obligations under the Act. Further, BellSouth observed that Matrix Item Nos. 36, 37, and 38 are all interrelated as they address BellSouth's line conditioning obligations in both a general and a specific fashion.

It is BellSouth's position that it is obligated to perform line conditioning on the same terms and conditions that BellSouth provides for its own customers. In particular, BellSouth contended that in Paragraph 643 of the *TRO*, the FCC stated that "line conditioning is properly seen as a routine network modification that incumbent LECs regularly perform in order to provide xDSL services to their own customers." BellSouth explained that the FCC went on further, in Paragraph 643, to state that "incumbent LECs must make the routine adjustments to unbundled loops to deliver services at parity with how incumbent LECs provision such facilities for themselves" and that "line conditioning is a term or condition that incumbent LECs apply to their provision of loops for their own customers and must offer to requesting carriers pursuant to their section 251(c)(3) nondiscrimination obligations."

BellSouth maintained that the Joint Petitioners conceded that "parity" means "equal" and that the FCC's rationale for establishing an obligation to perform line conditioning was based upon BellSouth's nondiscrimination obligation. Notwithstanding these concessions, BellSouth contended that the Joint Petitioners' position is that BellSouth's line conditioning obligations are established by the related FCC Rule, as provided in Appendix B of the *TRO*, which does not provide for the same definition of line conditioning that appears in Paragraph 643 of the *TRO*. BellSouth argued that the only interpretation of both Paragraph 643 as well as the FCC Rule that gives effect to both provisions is BellSouth's interpretation. It is BellSouth's opinion that to decide otherwise, would be to "read away" and ignore the FCC's express findings in Paragraph 643, because BellSouth would then be required to perform line conditioning for the Joint Petitioners that exceed what BellSouth provides for its own customers.

Furthermore, BellSouth asserted that the fact that the Joint Petitioners' current agreements contain TELRIC rates for line conditioning in excess of what BellSouth provides for its customers is of no consequence. BellSouth maintained that this is because their current agreements are not *TRO*-compliant since the FCC clarified in the *TRO* that BellSouth's line conditioning obligations are limited to what BellSouth routinely provides for its own customers. Thus, BellSouth contended that the Joint Petitioners' argument that not all line conditioning is a routine network modification should be rejected. BellSouth pointed out that in the FCC's discussion of routine network modifications, the FCC expressly equated its routine network modification rules to its line conditioning rules in the *TRO*, in Paragraph 635, stating that "In fact, the routine modifications we require today are substantially similar activities to those that the incumbent LECs currently undertake under our line conditioning rules." Furthermore, BellSouth noted that the FCC echoed these sentiments in Paragraph 250 of the *TRO*, which states that "As noted elsewhere in this Order, we find that line conditioning constitutes a form of routine network modification that must be performed at the competitive carrier's request to ensure that a copper local loop is suitable for providing xDSL service."

In addition, BellSouth observed that in response to KMC witness Johnson's testimony, BellSouth witness Fogle explained that witness Johnson's Venn diagram illustration actually proves that line conditioning is a subset of routine network modification. Witness Fogle testified that

> Well, I'll say that when I heard the use of a VIM [Venn] diagram, from an electrical engineering standpoint, that's very exciting in a hearing. Because it involves mathematics, and it's actually a whole area of mathematics called set theory. If you take a sentence or words and you want to convert to a VIM [Venn] diagram, there are actually mathematical definitions of words that are then used to create these VIM [Venn] diagrams. . . . If you take the sentence, line conditioning is properly seen as a network – as a routine network modification. The word 'properly' according to dictionaries and others, has a mathematical definition, and the mathematical definition is [a] subset. In other words, line conditioning is a subset of routine network modifications . . . So that all line conditioning is a subset of a routine network modification, but there are routine network modifications that are not considered line conditioning.

Based upon its foregoing arguments, BellSouth recommended that the Commission should harmonize Paragraph 643 and the FCC Rule by adopting BellSouth's language and finding that BellSouth's obligation is to provide the Joint Petitioners with line conditioning on the same terms and conditions that it provides to its own customers.

In its Proposed Order, the Public Staff agreed with the Joint Petitioners' position that BellSouth is obligated to provide line conditioning, without limitation, in accordance with FCC Rule 51.319 (a)(1)(iii). The Public Staff stated that Paragraph 643 of the *TRO* clearly reflects the FCC's belief that line conditioning does not constitute creation of a superior network and illustrates the FCC's point that load coil and bridge tap removal (i.e. line conditioning) are network modifications that ILECs perform on a routine basis to provide advanced services to their customers. The Public Staff contended that because ILECs routinely condition lines, performing line conditioning for a CLP does not constitute the creation of a superior network. Further, the Public Staff explained that since ILECs provide line conditioning for their retail customers, they must also offer line conditioning as a loop network element. The Public Staff asserted that the importance of line conditioning to CLPs is emphasized by the FCC when it states in Paragraph 643 that "[c]ompetitors cannot access the loop's inherent 'features, functions, and capabilities' unless it has been stripped of accretive devices."

The Public Staff stated that the FCC did not intend for Paragraph 643, in the *TRO*, to limit BellSouth's line conditioning obligations only to those situations in which BellSouth itself would perform these modifications for its own customers. Instead, the Public Staff contended that it is the function of removing load coils or bridge taps that constitutes a routine network modification, not the conditions under which these functions are performed. The Public Staff asserted that this is made clear in FCC Rule 51.319(a)(1)(iii)(A), which defines line conditioning "as the removal from a copper loop or copper subloop of any device that could diminish the capability of the loop or subloop to deliver high-speed switched wireline telecommunications capability, including digital subscriber line service. Such devices include, but are not limited to, bridge taps, load coils, low pass filters, and range extenders." The Public Staff maintained that the FCC's definition does not limit line conditioning to the removal of devices only in situations where BellSouth would typically remove them.

Furthermore, the Public Staff observed that Paragraph 642 of the *TRO* supports the view that ILECs are obligated to perform the functions associated with line conditioning because of the characteristics of xDSL service. The Public Staff explained that certain devices added to the local loop to provide voice service disrupt the capability of the loop in the provision of xDSL services. Thus, the Public Staff contended that because providing a local loop without conditioning the loop for xDSL services would fail to address the impairment CLPs face, the FCC requires ILECs to provide line conditioning to CLPs.

In addition, the Public Staff also observed that Footnote 1947 of the *TRO* states that the FCC refined the conditioning obligation to cover loops of any length in its *Line Sharing Order*[1]. Thus, the Public Staff asserted that even if an ILEC chooses not to condition loops of certain lengths, it is not absolved from its obligation to condition loops of any length upon request of a CLP.

Based upon the foregoing arguments of the parties, the Commission has reviewed the various sections of FCC orders referenced by the parties and, consequently, we begin our

[1] CC Docket No. 98-147 and CC Docket No. 96-98, released on December 9, 1999.

analysis by observing that in the FCC's *UNE Remand Order*, released November 5, 1999, at Paragraph 172, which concerns loop conditioning, the FCC stated the following:

> Conditioned Loops. We clarify that incumbent LECs are required to condition loops so as to allow requesting carriers to offer advanced services. The terms 'conditioned,' 'clean copper,' 'xDSL-capable' and 'basic' loops all describe copper loops from which bridge taps, low-pass filters, range extenders, and similar devices have been removed. Incumbent LECs add these devices to the basic copper loop to gain architectural flexibility and improve voice transmission capability. Such devices however, diminish the loop's capacity to deliver advanced services, and thus preclude the requesting carrier from gaining full use of the loop's capabilities. Loop conditioning requires the incumbent LEC to remove these devices, paring down the loop to its basic form. (Footnotes omitted.)

Thus, the Commission understands that in said Paragraph the FCC required the ILECs to condition loops by removing bridge taps, low-pass filters, range extenders, and similar devices from copper loops to allow requesting carriers to offer advanced services. The Commission also notes that the FCC in its Appendix C to the *UNE Remand Order* adopted its revised Rule 51.319 (Specific unbundling requirements) which included a Local Loop Section (a)(3) with subsections A-D regarding line conditioning. In addition, we note that that portion of the Rule is reflected, herein, under a previous footnote included within the discussion of this issue and, thus, it will not be repeated here. However, we are compelled to note, in part, that the Rule provides that "[t]he incumbent LEC shall condition lines required to be unbundled under this section wherever a competitor requests, whether or not the incumbent LEC offers advanced services to the end user customer on that loop.... Line conditioning is defined as the removal from the loop of any devices that may diminish the capability of the loop to deliver high-speed switched wireline telecommunications capability, including xDSL service".

On August 21, 2003, the FCC released its *TRO* and, therein, the FCC in its Appendix B to the *TRO* adopted its further revised Rule 51.319 which included a Local Loop – Copper Loops Section (a)(1)(iii) with its subsections A-E regarding line conditioning. As stated previously, Section (a)(1)(iii) states, in part, that "The incumbent LEC shall condition a copper loop at the request of the carrier seeking access to a copper loop under paragraph (a)(1) of this section, the high frequency portion of a copper loop under paragraph (a)(1)(i) of this section, or a copper subloop under paragraph (b) of this section to ensure that the copper loop or copper subloop is suitable for providing digital subscriber line services, including those provided over the high frequency portion of the copper loop or copper subloop, whether or not the incumbent LEC offers advanced services to the end-user customer on that copper loop or copper subloop." And Section (a)(1)(iii)(a) states, in part, that "[l]ine conditioning is defined as the removal from a copper loop or copper subloop of any device that could diminish the capability of the loop or subloop to deliver high speed switched wireline telecommunications capability, including digital subscriber line service. Such devices include, but are not limited to, bridge taps, load coils, low pass filters, and range extenders." Also, in the FCC's *TRO*-revised Rule 51.319, separate and apart from the line conditioning rule section, the FCC included another Local Loop Section (a)(8)(i-ii) regarding routine network modifications. The routine network modifications rule section states, in part, that "[a]n incumbent LEC shall make all routine network modifications to unbundled loop facilities used by requesting telecommunications carriers where the requested loop facility has already been constructed. . . . A routine network modification is an activity that the incumbent LEC regularly undertakes for its own customers. Routine network modifications include, but are not limited to, rearranging or splicing of cable; adding an equipment case; adding a doubler or repeater; adding a smart jack; installing a repeater shelf; adding a line card; deploying a new multiplexer or reconfiguring an existing multiplexer; and attaching electronic and other equipment that the incumbent LEC ordinarily attaches to a DS1 loop to activate such loop for its own customer."

On February 4, 2005, the FCC released its *TRRO*. In the *TRRO*, the FCC further revised Rule 51.319, however, the sections of the Rule concerning the line conditioning rules and the routine network modification rules were not changed by the FCC.

As discussed herein, BellSouth's argument is that its line conditioning obligations were changed by the *TRO*, as a result of the FCC's adoption of its routine network modification rules; therefore, BellSouth maintained that line conditioning should be defined as a routine network modification that BellSouth regularly undertakes to provide xDSL services to its own customers; and BellSouth's line conditioning obligations should be limited to what BellSouth routinely provides for its own customers. BellSouth has cited certain language in the *TRO* from Paragraphs 250, 635, and 643 in support of its position.

Based upon our review of the *TRO* as it relates to the matters at issue here, the Commission does not believe that BellSouth's line conditioning obligations were changed by the *TRO*. As discussed previously, BellSouth has cited certain excerpts of text from *TRO*-Paragraphs 250, 635, and 643, to support its position that the only interpretation of both Paragraph 643, as well as the FCC Rule that gives effect to both line conditioning and routine network modification provisions, is BellSouth's interpretation. We disagree with BellSouth's interpretation of the FCC's actions.

The *TRO* provided a discussion in Part VI.A.4.a.(v)(a), consisting of three Paragraphs (248-250), concerning "Legacy Networks" – "Stand-Alone Copper Loops". Paragraph 250 is worded as follows, including footnotes:

> **250.** The practical effect of this unbundling requirement is to ensure that requesting carriers have access to the copper transmission facilities they need in order to provide narrowband or broadband services (or both) to customers served by copper local loops. We understand that this unbundling obligation may require an incumbent LEC to provide the functionality available in certain equipment, as well as to remove the functionality from other equipment (*i.e.*, to condition the loop), in order to provide a complete transmission path between its main distribution frame (or equivalent) and the demarcation point at the customer's premises.[747] As noted elsewhere in this Order, we find that line conditioning constitutes a form of routine network modification that must be performed at the competitive carrier's request to ensure that a copper local loop is suitable for providing xDSL service.[748]
>
> [Footnotes for Paragraph 250:]
>
> [747] As discussed in Part VI.A. *infra*, we readopt incumbent LECs' line conditioning obligations. The Commission noted in its *Line Sharing Order* that devices such as load coils and bridged taps

interfere with the provision of xDSL service and, absent a certain showing by the incumbent LEC to the relevant state commission, must be removed at the request of the competitive LEC. *See Line Sharing Order*, 14 FCC Rcd at 20952-54, paras. 83-86. We determine that, upon the competitive LEC's request, incumbent LECs must similarly condition unbundled stand-alone loops to make them xDSL-compatible.

[748] We also require such conditioning for the HFPL consistent with the grandfather provision and transition period described below. *See Line Sharing Order*, 14 FCC Rcd at 20952-54, paras, 83-87.

The Commission does not believe that the FCC's statement from Paragraph 250, which states that "we find that line conditioning constitutes a form of routine network modification that must be performed at the competitive carrier's request to ensure that a copper local loop is suitable for providing xDSL service" requires that line conditioning should be defined as a routine network modification that BellSouth regularly undertakes to provide xDSL services to its own customers and that BellSouth's line conditioning obligations should be limited to what BellSouth routinely provides for its own customers. Instead, the Commission believes that this language means that the function of line conditioning, i.e., the removal of devices such as bridge taps, load coils, low pass filters, and range extenders, constitutes a form of routine network modification, not the conditions under which this function is performed. The Commission also notes that in Footnote 747, the FCC stated "we readopt incumbent LECs' line conditioning obligations."

Further on in the *TRO*, the FCC provided a discussion in Part VII.D.2.a., consisting of 10 Paragraphs (632-641), concerning "Routine Network Modifications to Existing Facilities". Paragraph 635 is worded as follows, including footnotes:

> **635.** The record reveals that attaching routine electronics, such as multiplexers, apparatus cases, and doublers, to high-capacity loops is already standard practice in most areas of the country.[1923] Moreover, performing such functions is easily accomplished. The record shows that requiring incumbent LECs to make the routine adjustments to unbundled loops discussed above that modify a loop's capacity to deliver services in the same manner as incumbent LECs provision such facilities for themselves is technically feasible[1924] and presents no significant operational issues.[1925] In fact, the routine modifications that we require today are substantially similar activities to those that the incumbent LECs currently undertake under our line conditioning rules.[1926] Specifically, based on the record, high-capacity loop modifications and line conditioning require comparable personnel; can be provisioned within similar intervals; and do not require a geographic extension of the network.[1927]
>
> [Footnotes for Paragraph 635:]
>
> [1923] The record reflects that different incumbent LECs perform varying degrees of network modifications when provisioning unbundled high-capacity loops. See, e.g., Letter from Patrick J. Donovan, Counsel for Cbeyond, to Marlene H. Dortch, Secretary, FCC, CC Docket Nos. 01-338, 96-98, 98-147 (Cbeyond Dec. 16, 2002 No Facilities Ex Parte Letter), Declaration of Richard Batelaan at paras. 8-9 (filed Dec. 16, 2002) (discussing the different "no facilities" policies of Qwest, SBC, and Verizon).

1924 See Allegiance Sept. 30, 2002 Ex Parte Letter at 5, Attach. 4 (citing Verizon Maryland, Inc.'s response to a data request stating "[g]enerally speaking, Verizon MD does not reject DS1 requests for end users due to no facilities.").

1925 See Allegiance Sept. 30, 2002 Ex Parte Letter at 2.

1926 See infra Part VII.D.2.b. Specifically, in the UNE Remand Order, the Commission held that incumbent LECs must remove certain devices, such as bridge taps, low-pass filters, and range extenders, from basic copper loops in order to enable the requesting carrier to offer advanced services. UNE Remand Order, 15 FCC Rcd at 3775, para. 172. Although Verizon rejects unbundled DS1 loop orders where there is no apparatus or doubler case on the loop claiming that installation of these cases is "complex" – requiring a truck roll to either dig up existing cable or a "bucket" to reach aerial cables in order to splice open the cable sheath – it must perform similar activities to accommodate line conditioning requests. See Letter from W. Scott Randolph, Director – Regulatory Affairs, Verizon, to Marlene H. Dortch, Secretary, FCC, CC Docket Nos. 01-338, 96-98, 98-147 at 4-5 (filed Oct. 18, 2002) (Verizon Oct. 18, 2002 No Facilities Ex Parte Letter); see also El Paso Galindo Decl. at para. 14 ("When an ILEC outside plant technician conditions a copper loop for xDSL by removing bridged tap and Load Coils in the loop, the work is generally performed by the same staff that performs rearrangement for DS1 services.").

1927 See Cbeyond Nov. 23, 2002 Ex Parte Letter at 3. Furthermore, these routine modifications are generally provided by incumbent LECs within relatively short intervals. Mpower Reply at 29 (stating that Verizon's customers "[i]n almost every instance . . . can order service and have it installed within one week.").

The Commission does not believe that the FCC's statement in Paragraph 635, that "the routine modifications that we require today are substantially similar activities to those that the incumbent LECs currently undertake under our line conditioning rules", supports BellSouth's position that line conditioning should be defined as a routine network modification that BellSouth regularly undertakes to provide xDSL services to its own customers and that BellSouth's line conditioning obligations should be limited to what BellSouth routinely provides for its own customers. To the contrary, the Commission believes that the FCC is simply stating that its required routine modifications are substantially similar activities to those undertaken by the ILECs, as required by the FCC's line conditioning rules. Furthermore, the Commission notes that in Footnote 1926, which is an integral part of the subject statement, the FCC referenced Part VII.D.2.b. of the *TRO* concerning line conditioning and explained that "[s]pecifically, in the UNE Remand Order, the Commission held that incumbent LECs must remove certain devices, such as bridge taps, low-pass filters, and range extenders, from basic copper loops in order to enable the requesting carrier to offer advanced services. UNE Remand Order, 15 FCC Rcd at 3775, para. 172. Although Verizon rejects unbundled DS1 loop orders where there is no apparatus or doubler case on the loop claiming that installation of these cases is 'complex' – requiring a truck roll to either dig up existing cable or a 'bucket' to reach aerial cables in order to splice open the cable sheath – it must perform similar activities to accommodate line conditioning requests."

Next, the *TRO* provided a discussion in Part VII.D.2.b., consisting of three Paragraphs (642-644), concerning "Line Conditioning". Paragraph 642 is worded as follows, including footnotes:

> **642.** As noted above, we conclude that incumbent LECs must provide access, on an unbundled basis, to xDSL-capable stand-alone copper loops because competitive LECs are impaired without such loops.[1946] Such access may require incumbent LECs to condition the local loop for the provision of xDSL-capable

services.[1947] Accordingly, we readopt the Commission's previous line and loop conditioning rules for the reasons set forth in the *UNE Remand Order*.[1948] Line conditioning is necessary because of the characteristics of xDSL service – that is, certain devices added to the local loop in order to facilitate the provision of voice service disrupt the capability of the loop in the provision of xDSL services. In particular, bridge taps, load coils, and other equipment disrupt xDSL transmissions.[1949] Because providing a local loop without conditioning the loop for xDSL services would fail to address the impairment competitive LECs face, we require incumbent LECs to provide line conditioning to requesting carriers.

[Footnotes for Paragraph 642:]

[1946] *See supra* Part VI.A.4.a.(v)(a).

[1947] In the *UNE Remand Order*, the Commission made clear that incumbent LECs must condition loops to allow requesting carriers to offer advanced services, and identified the removal of bridge taps, load coils, and similar devices as part of this obligation. *UNE Remand Order*, 15 FCC Rcd at 3775, para. 172. The Commission specifically rejected the contention that the Eighth Circuit's holding on "superior quality" overturned the rules requiring incumbents to provide conditioned loops even where the incumbent itself is not providing advanced services to those customers. *Id.* at 3775, para. 173 ("We find that loop conditioning, rather than providing a 'superior quality' loop, in fact enables a requesting carrier to use the basic loop."). The Commission subsequently refined the conditioning obligation to cover loops of any length, to recognize the potential degradation of analog voice service, and to enable incumbent LECs to charge for conditioning loops. *Line Sharing Order*, 14 FCC Rcd 20912, 20951-53, paras. 81-87.

[1948] We note that the *USTA* court did not expressly opine on the Commission's line and loop conditioning rules.

[1949] *See* Telcordia Technologies, Inc. NOTES ON DSL at 2-10 to 2-16 (describing limitations of xDSL service); Padmanand Warrier and Balaji Kumar, xDSL ARCHITECTURE 95-97 (2000) (describing the effect of bridge taps, load coils, various gauges of copper cable, and analog/digital conversions on xDSL transmissions); *see also Line Sharing Order*, 14 FCC Rcd at 20951-52, para. 83.

The Commission notes that the text of Paragraph 642 explicitly indicates that the FCC readopted its previous line and loop conditioning rules for the reasons set forth in the *UNE Remand Order*. In addition, in said Paragraph and Footnotes, the FCC (1) required incumbent LECs to provide access, on an unbundled basis, to xDSL-capable stand-alone copper loops because competitive LECs are impaired without such loops; (2) recognized that access to xDSL-capable stand-alone copper loops may require incumbent LECs to condition the local loop for the provision of xDSL-capable services; (3) explained that line conditioning is necessary because of the characteristics of xDSL service, i.e., certain devices added to the local loop to provide voice service disrupt the capability of the loop in the provision of xDSL services; (4) concluded that providing a local loop without conditioning the loop for xDSL services would fail to address the impairment CLPs face; (5) required incumbent LECs to provide line conditioning to requesting carriers; (6) identified the removal of bridge taps, load coils, and similar devices as part of the line conditioning obligation; and (7) observed that the *Line Sharing Order* refined the conditioning obligation to cover loops of any length, to recognize the potential degradation of analog voice service, and to enable incumbent LECs to charge for conditioning loops. Based upon the foregoing, the Commission does not believe that BellSouth's line conditioning obligations have now been constrained by the FCC's inclusion in Rule 51.319 of its routine network modifications' Section (a)(8).

Further, *TRO*-Paragraph 643 is worded as follows, including footnotes:

> 643. Line conditioning does not constitute the creation of a superior network, as some incumbent LECs argue.[1950] Instead, line conditioning is properly seen as a routine network modification that incumbent LECs regularly perform in order to provide xDSL services to their own customers. As noted above, incumbent LECs must make the routine adjustments to unbundled loops to deliver services at parity with how incumbent LECs provision such facilities for themselves. Similarly, in order to provide xDSL services to their own customers, incumbent LECs condition the customer's local loop.[1951] Thus, line conditioning is a term or condition that incumbent LECs apply to their provision of loops for their own customers and must offer to requesting carriers pursuant to their section 251(c)(3) nondiscrimination obligations. We therefore agree with the commenters that argue that requiring the conditioning of xDSL-capable loops is not mandating superior access,[1952] and reject Verizon's renewed challenge that the Commission lacks authority to require line conditioning.[1953] Competitors cannot access the loop's inherent 'features, functions, and capabilities' unless it has been stripped of accretive devices. We therefore view loop conditioning as intrinsically linked to the local loop and include it within the definition of the loop network element.[1954]

[Footnotes for Paragraph 643:]

[1950] *See* Verizon Jan. 17, 2003 Guyer *Ex Parte* Letter at 3-4 (arguing that line conditioning constitutes the creation of a superior network).

[1951] We note that all BOCs offer xDSL service throughout their service areas. *See, e.g.*, Verizon, *Verizon Online DSL for Your Home Including Personal or Office Use and Price Packages for DSL*, http://www22.verizon.com/ForHomeDSL/channels/dsl/forhomedsl.asp> (describing Verizon's xDSL offerings for residential customers).

[1952] *See, e.g.*, NuVox *et al.* Reply at 43; WorldCom Reply at 42-43.

[1953] Verizon Comments at 63 (arguing that "loop conditioning plainly is an unlawful requirement to provide a superior quality network."). More specifically, we do not accept Verizon's contention that line conditioning is a "significant construction activity" that provides a "*superior* quality network facility." Jan. 17, 2003 Verizon Guyer *Ex Parte* Letter at 4.

[1954] As the Commission noted in the *UNE Remand Order*, the Eighth Circuit expressly affirmed the Commission's determination that section 251(c)(3) requires incumbent LECs to provide modifications to their facilities in order to accommodate access to network elements. *UNE Remand Order*, 15 FCC Rcd at 3775, para. 173 (citing *Iowa Utils. Bd. v. FCC*, 120 F.3d at 813, n.33). With respect to making routine network modifications, the Eighth Circuit stated: "Although we strike down the Commission's rules requiring incumbent LECs to alter substantially their networks in order to provide superior quality interconnection and unbundled access, we endorse the Commission's statement that 'the obligations imposed by sections 251(c)(2) and 251(c)(3) include modifications to incumbent LEC facilities to the extent necessary to accommodate interconnection or access to network elements.'" *Iowa Utils. Bd. v. FCC*, 120 F.3d at 813, n.33 (citing *Local Competition Order*, 11 FCC Rcd at 15602-03, para. 198).

The Commission does not believe that the FCC's statement in Paragraph 643, that "line conditioning is properly seen as a routine network modification that incumbent LECs regularly perform in order to provide xDSL services to their own customers" supports BellSouth's position that line conditioning should be defined as a routine network modification that BellSouth regularly undertakes to provide xDSL services to its own customers and that BellSouth's line conditioning obligations should be limited to what BellSouth routinely provides for its own customers. The Commission believes that this language merely means that the function of line conditioning is to be properly seen as a routine network modification, i.e, the function of line conditioning, constitutes a form of routine network modification, not the conditions under which this function is performed. The Commission observes that in Footnote 1951, the FCC stated that "[w]e note that all BOCs offer xDSL service throughout their service areas." Furthermore, the FCC found that "Competitors cannot access the loop's inherent 'features, functions, and capabilities' unless it has been stripped of accretive devices. We therefore view loop conditioning as intrinsically linked to the local loop and include it within the definition of the loop network element." Consistent with that finding, the Commission notes that in the FCC's specific unbundling requirements, Rule 51.319(a)(1), the FCC provided, in part, that "A copper loop is a stand-alone local loop comprised entirely of copper wire or cable. Copper loops include two-wire and four-wire analog voice-grade copper loops, digital copper loops (e.g., DS0s and integrated services digital network lines), as well as two-wire and four-wire loops conditioned to transmit the digital signals needed to provide digital subscriber line services, regardless of whether the copper loops are in service or held as spares." (Emphasis added.)

The Commission rejects BellSouth's position that its line conditioning obligations are now constrained by the FCC's *TRO*-implemented rule on routine network modifications. The FCC did not modify the line conditioning definition in its *TRO* rules to allow for any routine network modification limitation as BellSouth is now seeking to impose on the definition for line conditioning. Moreover, the FCC concluded that line conditioning is intrinsically linked to the local loop; the FCC included line conditioning within the definition of an unbundled copper loop network element; and the FCC found that providing a local loop without conditioning the loop for xDSL services would fail to address the impairment CLPs face and, thus, the FCC required ILECs to provide line conditioning to the requesting carriers. The Commission believes that the ILECs' line conditioning obligations remained virtually the same as they did before the *TRO*, with the exception that the line conditioning obligations were expanded to include copper subloops. We understand that the CLPs need to have access to line conditioning at TELRIC rates, so that they will be able to deploy advanced services on copper loops (including subloops), free of devices that diminish the capabilities of the loop, and we also understand that the ILEC's line conditioning obligations apply to loops of any length. Based upon the foregoing, the Commission believes it is entirely appropriate to agree with the Joint Petitioners' and the Public Staff's positions such that line conditioning would be defined in the Agreement as set forth in FCC Rule 51.319(a)(1)(iii)(A); and BellSouth would be obligated to provide line conditioning in accordance with FCC Rule 51.319 (a)(1)(iii).

CONCLUSIONS

The Commission concludes that line conditioning should be defined in the Agreement as set forth in FCC Rule 51.319(a)(1)(iii)(A); and BellSouth should be required to perform line conditioning in accordance with FCC Rule 51.319(a)(1)(iii). Accordingly, the Commission adopts the Joint Petitioners' proposed language for inclusion in the Agreement, in Attachment 2, Section 2.12.1.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

ISSUE NO. 11 - MATRIX ITEM NO. 37:

Joint Petitioners' Issue Statement: Should the Agreement contain specific provisions limiting the availability of line conditioning to copper loops of 18,000 feet or less?

BellSouth's Issue Statement: Should the Agreement contain specific provisions limiting the availability of load coil removal to copper loops of 18,000 feet or less?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners argued that the Agreement should not contain specific provisions limiting the availability of line conditioning - in this case, load coil removal - to copper loops of 18,000 feet or less.

BELLSOUTH: BellSouth maintained that it has no obligation to remove load coils on copper loops in excess of 18,000 feet at TELRIC rates for the Joint Petitioners because BellSouth does not remove load coils on long loops for its own customers.

PUBLIC STAFF: The Public Staff agreed with the Joint Petitioners' position.

DISCUSSION

According to the Joint Petitioners' Petition for Arbitration and the Joint Petitioners' Exhibit A, this issue relates to the matter of the appropriate contract language to be included in Section 2.12.2 of Attachment 2 (Network Elements and Other Services) to the Agreement.

The Joint Petitioners asserted that the Agreement should not contain any specific contract language limiting the availability of line conditioning for load coil removal to only copper loops of 18,000 feet or less in length.

Whereas, BellSouth argued that the Agreement should contain specific language indicating that BellSouth has no obligation to remove load coils on copper loops in excess of 18,000 feet. However, BellSouth represented that it will remove such load coils upon request of a CLP, but only pursuant to special construction pricing, which would allow BellSouth's engineers to evaluate the specific costs associated with removing and replacing such an individual load coil.

The specific language proposed to be included in the Agreement in Attachment 2, Section 2.12.2 is as follows:

Joint Petitioners' Version –

No Section.

BellSouth's Version –

> BellSouth will remove load coils only on copper loops and sub loops that are less than 18,000 feet in length. BellSouth will remove load coils on copper loops and sub loops that are greater than 18,000 feet in length upon <<customer_short_name>>'s request at rates pursuant to BellSouth's Special Construction Process contained in BellSouth's FCC No. 2 as mutually agreed to by the Parties.

This issue is essentially a subpart of the issue previously addressed in the Evidence and Conclusions for Finding of Fact No. 10, concerning Matrix Item No. 36. Thus, consistent with their position regarding Matrix Item No. 36, the Joint Petitioners asserted that BellSouth should not be permitted to impose artificial restrictions on its obligation to provide line conditioning at Commission-approved TELRIC-compliant rates. The Joint Petitioners maintained that BellSouth should be required to remove load coils at TELRIC rates on loops of any length as required by the FCC's line conditioning rules. The Joint Petitioners argued that BellSouth's refusal to remove load coils on loops greater than 18,000 feet at TELRIC rates because BellSouth believes that such activity is not a routine network modification as defined by the FCC, is a flawed interpretation of the FCC's line conditioning rules. As discussed previously, in regard to Matrix Item No. 36, the Joint Petitioners again argued that BellSouth's line conditioning obligations are not constrained by the FCC's routine network modification rule.

Further, in their Brief, the Joint Petitioners observed that the Commission has already set TELRIC rates for load coil removal on loops of all lengths. In particular, the Joint Petitioners noted that, during the hearing, BellSouth witness Fogle was provided with the Joint Petitioners Cross-Examination Exhibit 4, which was an excerpt from BellSouth's current interconnection agreement with NewSouth, which included a detailed table of the rates applied to load coil removal; and the Joint Petitioners commented that witness Fogle agreed that these rates are TELRIC-compliant and had been set by the Commission. Consequently, the Joint Petitioners asserted that in seeking to impose unpredictable, individual case basis, FCC tariff Special Construction Rates for load coil removal on long loops, BellSouth is attempting to circumvent the rates set by prior order of this Commission. The Joint Petitioners maintained that they are not willing to waive the application of these rates; thus, they opposed the inclusion of BellSouth's proposed language for Section 2.12.2. Accordingly, the Joint Petitioners recommended that the Commission should adopt the Joint Petitioners' position to ensure the applicability of its TELRIC rates for load coil removal on loops, including those that are greater than 18,000 feet in length, and to avoid the imposition of the artificial conditioning limitation that BellSouth seeks to impose contrary to the ILEC's conditioning obligations under existing FCC line conditioning rules and rulings.

In its Brief, BellSouth maintained that for the same reasons as discussed in its comments for Matrix Item No. 26, the Commission should move Matrix Item No. 37 to the change of law docket (Docket No. P-55, Sub 1549) for consideration and resolution because similar if not identical issues are being raised in the change of law proceeding. At a minimum, BellSouth asserted that the Commission should defer resolution of this item until its decision in the change of law proceeding to avoid inconsistent rulings.

However, in the event the Commission chooses to address this issue now, BellSouth argued that the Joint Petitioners' position should be rejected because it conflicts with the *TRO* and BellSouth's nondiscriminatory obligations under the Act. Further, BellSouth commented that Matrix Item Nos. 36, 37, and 38 are all interrelated as they address BellSouth's line conditioning obligations in both a general and a specific fashion.

BellSouth asserted that it should have no obligation to remove load coils in excess of 18,000 feet at TELRIC rates for the Joint Petitioners because BellSouth does not remove load coils on long loops for its own customers. BellSouth noted that as it commented in regard to Matrix Item No. 36, this standard complies with Paragraph 643 of the *TRO*, as well as BellSouth's nondiscrimination obligations under the Act. Further, BellSouth explained that, if requested, it will remove load coils on such loops pursuant to its FCC tariff via the special construction process.

Additionally, BellSouth explained that pursuant to current network standards, BellSouth places load coils on loops greater than 18,000 feet to enhance voice service. As stated by witness Fogle, "[w]e start placing them at 18,000 feet, and it essentially takes static off the line so your voice service works better." BellSouth indicated that it placed load coils, generally in groups of 400 or more, after 18,000 feet when the network was originally built; and according to witness Fogle those load coils were designed to be in the network for long periods of time. Consequently, witness Fogle testified that load coils are generally found inside splice cases that are typically buried underground, and they could be under concrete or asphalt. As a result of the difficulties encountered in removing such load coils and because BellSouth believes it has no obligation to remove load coils on loops in excess of 18,000 feet since it does not remove load coils on long loops for its own customers, BellSouth asserted that it will remove such load coils upon request of a CLP, but only pursuant to special construction pricing, which allows BellSouth's engineers to evaluate the specific costs associated with removing and replacing an individual load coil.

The Public Staff agreed with the Joint Petitioners' position. The Public Staff maintained that since load coil removal on loops greater than 18,000 feet is in effect providing line conditioning on those loops, then for the same reasons supporting its position on Matrix Item No. 36, the Agreement should not contain specific provisions limiting the availability of line conditioning to copper loops of 18,000 feet or less. The Public Staff also noted that the FCC's *Line Sharing Order* makes the conditioning obligation cover loops of any length. Thus, the Public Staff asserted that adopting BellSouth's language would conflict with this requirement and would permit BellSouth to limit offerings by the Joint Petitioners. Consequently, the Public Staff agreed with the Joint Petitioner's position that the Agreement should not contain specific provisions limiting the availability of line conditioning to copper loops of 18,000 feet or less in length.

The Commission, as previously concluded in regard to Matrix Item No. 36 (Issue No. 10), rejects BellSouth's assertion that its line conditioning obligations are now constrained by the FCC's *TRO*-implemented rule on routine network modifications, i.e., BellSouth asserted that its obligations to provide line conditioning at TELRIC rates should be limited to what

BellSouth routinely provides for its own customers. The Commission agrees with the Joint Petitioners' and the Public Staff's position. Consistent with our findings and conclusions in regard to Matrix Item No. 36, we find that the Agreement should not contain specific provisions limiting the availability of line conditioning to copper loops of 18,000 feet or less in length. In particular, as discussed in the Evidence and Conclusions for Finding of Fact No. 10 (Matrix Item No. 36), we found that (1) the ILECs' line conditioning obligations remained virtually the same as they did before the *TRO*, with the exception that the line conditioning obligations were expanded to include subloops; (2) the CLPs need to have access to line conditioning at TELRIC rates, so that they will be able to deploy advanced services on copper loops (including subloops), free of devices that diminish the capabilities of the loop; and (3) the ILEC's line conditioning obligations apply to loops of any length. Furthermore, we note that the Commission has previously concluded in its *Recommended Order Concerning all Phase I and Phase II Issues Excluding Geographic Deaveraging*, issued June 7, 2001, in Docket No. P-100, Sub 133d, that ILECs are obligated, pursuant to the FCC's *UNE Remand Order* and its line conditioning rules, to remove load coils from loops of any length at TELRIC rates.

CONCLUSIONS

The Commission concludes that the Agreement should not contain any specific contract language limiting the availability of line conditioning for load coil removal to only copper loops of 18,000 feet or less in length.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

ISSUE NO. 12 - MATRIX ITEM NO. 38: Under what rates, terms, and conditions should BellSouth be required to perform line conditioning to remove bridged taps?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners commented that any copper loop being ordered by a CLP with over 6,000 feet of combined bridged tap will be modified, upon request from the CLP, at no additional charge, so that the loop will have a maximum of 6,000 feet of bridged tap. Line conditioning orders that require the removal of other bridged tap should be performed at the rates set forth in Exhibit A of Attachment 2 to the Agreement.

BELLSOUTH: BellSouth stated that any copper loop being ordered by a CLP that has over 6,000 feet of combined bridged tap will be modified, upon request from the CLP, so that the loop will have a maximum of 6,000 feet of bridged tap. Such modification will be performed at no additional charge to the CLP. Line conditioning orders that require the removal of bridged tap which serves no network design purpose on a copper loop, that will result in a combined level of bridged tap between 2,500 feet and 6,000 feet will be performed at the rates set forth in Exhibit A of Attachment 2 to the Agreement. A CLP may request the removal of any unnecessary and non-excessive bridged tap (bridged tap between 0 and 2,500 feet which serves no network design purpose), at rates pursuant to BellSouth's special construction process. BellSouth is only required to perform line conditioning that it performs for its own xDSL customers.

PUBLIC STAFF: The Public Staff agreed with the Joint Petitioners' position.

DISCUSSION

According to the Joint Petitioners' Petition for Arbitration and the Joint Petitioners' Exhibit A, this issue relates to the matter of the appropriate contract language to be included in Section 2.12.3 and Section 2.12.4 of Attachment 2 (Network Elements and Other Services) to the Agreement.

BellSouth has agreed to remove bridged tap in excess of 6,000 feet from copper loops without charge. The Joint Petitioners and BellSouth have also agreed to TELRIC rates for the removal of bridged tap between 2,500 feet and 6,000 feet in length. The disputed issues between the parties are the cost for removal of bridged tap from copper loops between 0 and 2,500 feet in length and BellSouth's proposed limitation that only bridged tap between 0 and 6,000 feet which "serves no network design purpose" will be removed in accordance with BellSouth's rate proposals.

The Joint Petitioners asserted that Sections 2.12.3 and 2.12.4 of Attachment 2 of the Agreement should provide that BellSouth will remove bridged tap between 0 and 2,500 feet in length from any copper loop ordered by a CLP at TELRIC rates.

Whereas, BellSouth contended that, upon request by a CLP, it will remove bridged taps between 0 and 2,500 feet which serves no network design purpose pursuant to special construction pricing.

The specific language proposed to be included in the Agreement in Attachment 2, Section 2.12.3 and Section 2.12.4 is as follows, with the differences between the Joint Petitioners' proposal and BellSouth's proposal being denoted with underlined text:

Joint Petitioners' Version – Section 2.12.3

> Any copper loop being ordered by <<customer_short_name>> which has over 6,000 feet of combined bridged tap will be modified, upon request from <<customer_short_name>>, so that the loop will have a maximum of 6,000 feet of bridged tap. This modification will be performed at no additional charge to <<customer_short_name>>. Line conditioning orders that require the removal of <u>other</u> bridged tap will be performed at the rates set forth in Exhibit A of this Attachment.

BellSouth's Version – Section 2.12.3

> Any copper loop being ordered by <<customer_short_name>> which has over 6,000 feet of combined bridged tap will be modified, upon request from <<customer_short_name>>, so that the loop will have a maximum of 6,000 feet of bridged tap. This modification will be performed at no additional charge to <<customer_short_name>>. Line conditioning orders that require the removal of bridged tap <u>that serves no network design purpose on a copper loop that will result in a combined level of bridged tap between 2,500 and 6,000 feet</u> will be performed at the rates set forth in Exhibit A of this Attachment.

Joint Petitioners' Version – Section 2.12.4

No Section.

BellSouth's Version – Section 2.12.4

<<customer_short_name>> may request removal of any unnecessary and non-excessive bridged tap (bridged tap between 0 and 2,500 feet which serves no network design purpose), at rates pursuant to BellSouth's Special Construction Process contained in BellSouth's FCC No. 2 as mutually agreed to by the Parties.

This issue, like Matrix Item No. 37, is essentially a subpart of the issue addressed in the Evidence and Conclusions for Finding of Fact No. 10, concerning Matrix Item No. 36. As with Matrix Item No. 37, the Joint Petitioners asserted that BellSouth is relying on its incorrect interpretation of the routine network modification rule for its refusal to remove bridged tap less than 2,500 feet in length from copper loops at TELRIC rates. Like Matrix Item No. 37, the Joint Petitioners observed that this issue would be resolved in the Joint Petitioners' favor with the proper resolution of the issue in Matrix Item No. 36.

As discussed previously in regard to Matrix Item No. 36, the Joint Petitioners again argued that BellSouth's line conditioning obligations are not constrained by the routine network modification rule. The Joint Petitioners disagreed with BellSouth's position which was that since BellSouth does not remove bridged tap less than 2,500 feet in length from copper loops serving its own retail customers, this activity is not a routine network modification. The Joint Petitioners further explained that since BellSouth incorrectly equates line conditioning with routine network modification, then BellSouth considers that this type of bridged tap removal does not constitute line conditioning and need not be done at TELRIC rates. However, consistent with their position on Matrix Item No. 36, the Joint Petitioners again argued that the FCC does not equate line conditioning and routine network modifications. The Joint Petitioners opined that they are separate and distinct rules. The Joint Petitioners contended that the ILEC's line conditioning obligations are not modified or limited by the routine network modification rules. The Joint Petitioners observed that there was no length limitation in the FCC line conditioning rules before the *TRO*, and there is none now. Consequently, the Joint Petitioners maintained that BellSouth remains obligated to remove bridged tap from loops of any length pursuant to Section 251(c)(3) of the Act and FCC Rule 51.319(a)(1)(iii)(A).

Next, the Joint Petitioners noted that BellSouth has proposed to limit bridged tap removal to that which "serves no network design purpose." In opposition, the Joint Petitioners asserted that there is no legal basis for that purported standard. The Joint Petitioners maintained that such a standard would provide BellSouth with the sole discretion to determine when bridged tap would be removed.

Further, in regard to BellSouth's argument that requiring it to remove bridged tap of this length would create a "superior network" for Joint Petitioners, the Joint Petitioners commented that the FCC has expressly stated that "[l]ine conditioning does not constitute the creation of a superior network, as some incumbent LECs argue."[1] Accordingly, the Joint Petitioners argued that the proposed implementation of FCC Rule 51.319 as to line conditioning does not violate

[1] *TRO*, at Paragraph 643.

any precept of parity, but rather comports exactly with the FCC's own interpretation of an ILEC's conditioning responsibilities.

Additionally, the Joint Petitioners observed that, as with load coils, the Commission has previously concluded in its *Recommended Order Concerning all Phase I and Phase II Issues Excluding Geographic Deaveraging*, issued June 7, 2001, in Docket No. P-100, Sub 133d, that ILECs were obligated, pursuant to the FCC's *UNE Remand Order* and its line conditioning rules, to remove bridge taps from loops of any length at TELRIC rates. Further, the Joint Petitioners noted that the Joint Petitioners Cross-Examination Exhibit 4 included rates for removing bridged taps for all loops, and that during cross-examination, in regard to said Exhibit 4, BellSouth witness Fogle testified that those rates were TELRIC rates set by this Commission. Consequently, the Joint Petitioners argued that BellSouth should not be permitted to impose other rates — particularly "Special Construction" rates — in contravention of the Commission's decision. Thus, the Joint Petitioners requested that the Commission adopt the Joint Petitioners' language for Sections 2.12.3 and 2.12.4.

In its Brief, BellSouth maintained that for the same reasons as discussed in its comments for Matrix Item No. 26, the Commission should move Matrix Item No. 38 to the change of law docket (Docket No. P-55, Sub 1549) for consideration and resolution because similar if not identical issues are being raised in the change of law proceeding. At a minimum, BellSouth contended that the Commission should defer resolution of this item until its decision in the change of law proceeding to avoid inconsistent rulings.

However, in the event the Commission chooses to address this issue now, BellSouth argued that the Joint Petitioners' position should be rejected because it conflicts with the *TRO* and BellSouth's nondiscriminatory obligations under the Act. Further, BellSouth commented that Matrix Item Nos. 36, 37, and 38 are all interrelated as they address BellSouth's line conditioning obligations in both a general and a specific fashion.

BellSouth commented that the dispute concerning Matrix Item No. 38 centers on whether BellSouth should be required to remove bridge taps between 0 and 2,500 feet at TELRIC rates. BellSouth alleged that bridge taps are standard network enhancements that are used to allow BellSouth to reconfigure its network without reconfiguring the copper wire and that BellSouth deploys bridge taps in its network pursuant to industry standards. Further, in its Brief, BellSouth noted that even though BellSouth does not remove bridge taps at any length for its own customers, in conjunction with the CLP Shared Loop Collaborative, BellSouth has agreed to remove bridge taps for CLPs in the following scenarios: (1) over 6,000 feet for free; (2) between 2,500 feet and 6,000 feet at TELRIC; and (3) between 0 and 2,500 feet pursuant to special construction pricing. BellSouth has offered these same terms and conditions to the Joint Petitioners. Furthermore, BellSouth asserted that no carrier has ever asked BellSouth to remove bridge taps of this length; none of the services that the Joint Petitioners are providing would be impacted by bridge taps of this length; and the Joint Petitioners cannot present any evidence to rebut this fact because they do not even know the percentage of its loops that contain bridge taps of this length or whether they have ever asked BellSouth to remove bridge taps. BellSouth remarked that this lack of knowledge to support their claim is not surprising given that the Joint Petitioners did not participate in the CLP Shared Loop Collaborative. Accordingly, BellSouth recommended that the Commission reject the Joint Petitioners' language on this issue and adopt

BellSouth's, as it provides the Joint Petitioners with exactly what the CLP Shared Loop Collaborative has already agreed to.

The Public Staff noted that the Joint Petitioners argued that BellSouth's proposed language would limit the removal of bridged tap between 2,500 feet and 6,000 feet that serves no network design purpose. The Public Staff asserted that this language leaves to BellSouth's discretion the determination of which bridged taps serve no network purpose and precludes the removal of bridged tap that is less than 2,500 feet that could possibly inhibit the provision of high-speed data transmission.

The Public Staff observed that, as with Matrix Item Nos. 36 and 37, BellSouth maintained that it has no obligation under Section 251 of the Act to perform bridged tap removal beyond what it performs for its own customers. Furthermore, the Public Staff pointed out that, nevertheless, BellSouth acknowledged that it currently offers bridged tap removal beyond what it contends are its obligations under Section 251, as a result of a process developed by the CLP Shared Loop Collaborative.

The Public Staff maintained that for the reasons supporting its position on Matrix Item No. 36, the Commission should find that BellSouth should perform line conditioning to remove bridged taps, without limitation as to the length of the bridged tap. The Public Staff argued that BellSouth has an obligation to condition loops regardless of the loop's length and may not limit the Joint Petitioners' offerings based on its own practices and procedures.

The Public Staff also observed that the parties concur that BellSouth has agreed through an industry collaborative to modify any copper loop ordered by a CLP at no additional charge to the CLP with over 6,000 feet of combined bridged tap, such that the loop will have a maximum of 6,000 feet of bridged tap. The Public Staff asserted that because loop conditioning is a Section 251 obligation, BellSouth must charge TELRIC-based rates for conditioning loops with combined bridged tap of 6,000 feet or less. Accordingly, the Public Staff recommended that the Commission find that any copper loop ordered by a CLP with over 6,000 feet of combined bridged tap would be modified, upon request from the CLP, at no additional charge to the CLP, so that the loop will have a maximum of 6,000 feet of bridged tap and that line conditioning orders that require the removal of other bridged tap should be performed at the BellSouth UNE rates previously adopted by the Commission.

The Commission, as previously concluded in regard to Matrix Item No. 36 (Issue No. 10), rejects BellSouth's assertion that its line conditioning obligations are now constrained by the FCC's *TRO*-implemented rule on routine network modifications, i.e., BellSouth asserted that its obligations to provide line conditioning at TELRIC rates should be limited to what BellSouth routinely provides for its own customers. In addition, the Commission rejects BellSouth's proposal to further limit the removal of bridged tap to that which "serves no network design purpose"; the FCC did not modify the line conditioning rules to allow such a limitation and the allowance of such a limitation would, inappropriately, provide BellSouth with the sole discretion to further determine when bridged tap would be removed. The Commission agrees with the Joint Petitioners' and the Public Staff's position. Consistent with our findings and conclusions in regard to Matrix Item No. 36, we conclude that BellSouth is required by the FCC's rulings regarding line conditioning to condition copper loops to remove bridged tap between 0 to 6,000 feet at TELRIC rates. In particular, as discussed in the Evidence and

Conclusions for Finding of Fact No. 10 (Matrix Item No. 36), we found that (1) the ILECs' line conditioning obligations remained virtually the same as they did before the *TRO*, with the exception that the line conditioning obligations were expanded to include subloops; (2) the CLPs need to have access to line conditioning at TELRIC rates, so that they will be able to deploy advanced services on copper loops (including subloops), free of devices that diminish the capabilities of the loop; and (3) the ILEC's line conditioning obligations apply to loops of any length.

CONCLUSIONS

The Commission accepts the parties' agreement that any copper loop ordered by a CLP with over 6,000 feet of combined bridged tap will be modified, upon request from the CLP, at no additional charge, so that the loop will have a maximum of 6,000 feet of bridged tap. The Commission concludes that line conditioning orders that require the removal of other bridged tap (bridged tap between 0 and 6,000 feet) should be performed at the BellSouth UNE rates previously adopted by the Commission. Accordingly, the Commission adopts the Joint Petitioners' proposed language for inclusion in the Agreement in Attachment 2, Section 2.12.3 and Section 2.12.4.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

ISSUE NO. 13 - MATRIX ITEM 51:

(B) Should there be a notice requirement for BellSouth to conduct an audit and what should the notice include?

(C) Who should conduct the audit and how should the audit be performed?

POSITIONS OF PARTIES

JOINT PETITIONERS: With respect to (B) the Joint Petitioners position is that to invoke its limited right to audit CLP records in order to verify compliance with the high capacity EEL service eligibility criteria, BellSouth should send a Notice of Audit to the CLPs, identifying particular circuits for which BellSouth alleges noncompliance and demonstrating the cause upon which BellSouth rests its allegations. The Notice of Audit should also include all supporting documentation upon which BellSouth relies to form the basis of its allegations of noncompliance. Such Notice of Audit should be delivered to the CLPs with all supporting documentation no less than 30 days prior to the date upon which Bellsouth seeks to commence an audit.

With respect to (C) the Joint Petitioners argued that the audit should be conducted by a third-party independent auditor mutually agreed-upon by the Parties. The provisions regarding when a CLP must reimburse BellSouth and when BellSouth must reimburse a CLP should mirror those contained in the *TRO*.

BELLSOUTH: BellSouth argued that this matter should be moved to the change of law docket for consideration and resolution because similar if not identical issues are being raised in the change of law proceeding. At a minimum the Commission should defer resolution of this item until its decision in the change of law docket to avoid inconsistent rulings.

On the merits, BellSouth's view is that the Joint Petitioners are attempting to impose unnecessary conditions on BellSouth's EEL audit right in contravention of the *TRO* by seeking to limit its audit rights to those circuits identified in the Notice of Audit and for which sufficient documentation is produced to support the audit and by regulating BellSouth's choice of auditor.

PUBLIC STAFF: The Public Staff believes that the *TRO* sufficiently outlines the requirements for an audit. However, 30-45 days notice of the audit provides a CLP with adequate time to prepare. BellSouth should be able to select the independent auditor of its choice without prior approval from the CLPs or the Commission. Challenges to the independence of the auditor may be filed with the Commission only after the audit has been concluded. BellSouth should not be required to provide documentation to support its basis for audit or seek concurrence of the requesting carrier before selecting the audit's location.

DISCUSSION

(B) The first issue has to do with whether there is a notice requirement and, if so, what should the notice contain. The Joint Petitioners argued that BellSouth must send a Notice of Audit to a CLP when it chooses to invoke its limited right to audit the CLP's records to verify compliance with the high capacity EEL service eligibility criteria. They contended that the notice should include all supporting documentation forming the basis of the allegation of noncompliance and be delivered no less than 30 days prior to the audit's commencement. The Joint Petitioners maintain that a CLP is entitled to know the basis for the audit and needs sufficient time to evaluate the audit request and prepare for an audit. Conversely, BellSouth maintained that the *TRO* contains no requirement that it provide notice of an audit, identify the specific circuits to be audited, or provide supporting documentation justifying the audit 30 days prior to the its commencement.

Paragraph 622 of the *TRO* adopts certification and auditing procedures comparable to those previously established in the *Supplemental Order Clarification* (SOC). The FCC held in the *TRO* that an ILEC may conduct limited audits to the extent reasonably necessary to determine a requesting carrier's compliance with the local usage options. The FCC allowed audits to be conducted on an annual basis because this period appropriately balances the ILEC's need for usage information and a CLP's risk of costly and illegitimate audits. The Joint Petitioners admitted that the *TRO* does not include a specific notice requirement, but contended that this Commission may order such a requirement.

BellSouth is correct that the *TRO* does not require ILECs provide notice of an audit or supporting documentation. Paragraph 622, however, notes that CLPs should not be impeded from access to UNEs based upon self-certification, subject to later verification based upon cause. The FCC also recognized in Paragraph 625 that the "details surrounding the implementation of these audits may be specific to related provisions of the interconnection agreements or to the facts of a particular audit, and that the states are in a better position to address that implementation."

While the *TRO* does not require notice of the audit, advance notice of audit would afford a CLP the opportunity to compile the appropriate documentation to support its certifications. Additionally, 30 to 45 days notice of the audit represents an adequate amount of time to prepare for the audit.

As the *TRO* grants ILECs limited authority to audit compliance with the qualifying service criteria on no more than an annual basis, the Commission is satisfied that ILECs by virtue of this authority, need not supply requesting carriers with additional documentation to support their audit rights, *except that, as distinct from documentation, BellSouth should state its concern that the requesting carrier has not met the qualification criteria and should set forth a concise statement of the reasons therefor.* In any event, BellSouth has agreed to provide notice to a CLP stating the cause for the audit. The Commission finds this proposal to be reasonable.

(C) The second issue concerns who is to perform the audit and how the audit should be performed. The Joint Petitioners believe that BellSouth's proposed language is inadequate because it does not provide that (1) the independent auditor must be a third-party retained by BellSouth; (2) the parties must reach agreement on the independent auditor before an audit may commence; (3) the location of the audit will be mutually agreeable to the parties; (4) that the audit will commence no sooner than 30 calendar days after the parties agree on the auditor; and (5) the American Institute of Certified Public Accountants (AICPA) standards related to determining the independence of the auditor will apply. Further, the Joint Petitioners contended that BellSouth's refusal to accept these provisions is contrary to the FCC's EEL audit regulations.

BellSouth asserted that the requirements the Joint Petitioners are attempting to add do not appear in the *TRO*. Further the requirement for a "third-party, mutually agreed-upon, auditor" is only a delaying tactic. BellSouth cited the *TRO* to support its position that it may select and pay for an independent auditor to conduct the audit.

The Commission addressed the issue of auditor selection in Docket No. P-772, Sub 7, in its Order Granting Motion for Summary Disposition and Allowing Audit issued on August 24, 2004, and Order Denying Motion for Reconsideration issued on January 20, 2004. In these Orders, the Commission found that BellSouth must choose an independent auditor to conduct an audit of the CLP's EELs, but that BellSouth may select the auditor without the prior approval of the CLP or Commission. Further, the Commission found it unnecessary to conduct a hearing to test the independence of BellSouth's selected auditor.

Paragraph 626 of the *TRO* concludes that an ILEC may obtain and pay for an independent auditor to audit compliance with the qualifying service eligibility criteria annually in accordance with the standards established by the AICPA. These standards require the auditor to perform an "examination engagement" and issue an opinion regarding the CLP's compliance with the qualifying service eligibility criteria. Paragraphs 627, 628, and 629 provide additional requirements for the auditor and the presentation of his findings. Paragraphs 627 and 628 specify that the ILEC must reimburse the audited carrier for its costs associated with the audit if the independent auditor concludes that the requesting carrier complied in all material respects with the eligibility criteria. Conversely, if the independent auditor concludes that the requesting carrier failed to comply in all material respects with the service eligibility criteria, the requesting carrier must reimburse the ILEC for the cost of the independent auditor. The FCC, however, does not specify the location of the audit or require that the parties agree to any particular location.

This Commission is not persuaded that the additional requirements suggested by the Joint Petitioners are necessary in light of the audit requirements in the *TRO*. The Commission agrees with BellSouth that the imposition of these superfluous requirements will serve only to delay the audit unnecessarily. The *TRO* clearly delineates the requirements for the audit and carefully assigns cost responsibilities based on the audit's findings.

CONCLUSIONS

The Commission concludes that the *TRO* sufficiently outlines the requirements for an audit. However, 30 - 45 days notice of the audit provides a CLP with adequate time to prepare. In its Notice of Audit, BellSouth should state its concern that the requesting CLP has not met the qualification criteria and a concise statement of its reasons therefor. The Commission further concludes that BellSouth may select the independent auditor without the prior approval of the CLP or this Commission. Challenges to the independence of the auditor may be filed with the Commission after the audit has concluded. Additionally, the Commission concludes that BellSouth is not required to provide documentation, as distinct from a statement of concern, to support its basis for audit or seek concurrence of the requesting carrier before selecting the audit's location.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

ISSUE NO. 14 - MATRIX ITEM NO. 65: Should BellSouth be allowed to charge the CLP a TIC for the transport and termination of Local Transit Traffic and ISP-Bound Transit Traffic?

POSITIONS OF PARTIES

JOINT PETITIONERS: No. BellSouth should not be permitted to impose upon CLPs a TIC for the transport and termination of Local Transit Traffic and ISP-Bound Transit Traffic. The TIC is a non-TELRIC based additive charge that exploits BellSouth's market power and is discriminatory.

BELLSOUTH: Yes. BellSouth is not obligated to provide the transit function and the CLP has the right pursuant to the Act to request direct interconnection to other carriers. Additionally, BellSouth incurs costs beyond those for which the Commission ordered rates were designed to address, such as the costs of sending records to the CLPs identifying the originating carrier. BellSouth does not charge the CLP for these records and does not recover those costs in any other form. Moreover, this issue is not appropriate for arbitration in this proceeding because it involves a request by the CLPs that is not encompassed within BellSouth's obligations pursuant to Section 251 of the Act.

PUBLIC STAFF: The Public Staff recommended that the Commission conclude that BellSouth should not be permitted to charge a TIC when providing a tandem transit function for CLPs.

DISCUSSION

The Joint Petitioners argued that the TIC is a non-TELRIC based additive charge enabling BellSouth to exploit its market power. The Joint Petitioners asserted that only BellSouth is in a position to provide transit service capable of connecting all carriers of all sizes, due to its past monopoly and continuing market dominance. The rate appears to be purely additive, simply enabling BellSouth to extract additional profits over and above the profit it already receives through the elemental UNE rates. In addition, the Joint Petitioners claimed that the TIC charge is discriminatory, since BellSouth does not impose this charge on all CLPs. Further, BellSouth threatened to double the rate if two of the Joint Petitioners did not agree to it during negotiations. The Joint Petitioners contended that BellSouth has not shown that its existing rates for the transiting function, tandem switching and common transport, do not adequately provide for recovery of its costs. The Joint Petitioners argued that BellSouth can seek to modify its TELRIC-based rates in the next generic pricing proceeding if its rates do not recover its costs. Despite BellSouth's contention that this issue should not be included in this arbitration, the Joint Petitioners argued that this issue is properly before the Commission because transiting is an interconnection issue and has been included in BellSouth's interconnection agreements for nearly eight years.

BellSouth initially contended that it was not required to provide a transit traffic function because it is not a Section 251 obligation under the Act. Therefore, BellSouth argued that if it provides the transit traffic function, the rates, terms, and conditions should be contained in a separately negotiated agreement. If BellSouth includes the transit traffic function in its Agreement, BellSouth believed that it should not be penalized by imposing rates for a service that, pursuant to a separate agreement, to which the Commission would not even be privy.

BellSouth maintained that it should be able charge a TIC for local transit and ISP-bound transit traffic because it is not obligated to provide the transit function to a CLP and the CLP has the ability to request direct interconnection to other carriers. BellSouth argued that the TIC is not "purely additive" because some costs are not recovered in tandem switching and common transport charges, such as the fee BellSouth pays to Telcordia for all messages sent and received through the Centralized Message Distribution System (CMDS). Moreover, BellSouth argued that because the TIC is not a Section 251 requirement, the rate should not be subject to the TELRIC cost standards set forth in Section 252.

In cross-examination, BellSouth witness Blake acknowledged that BellSouth has offered to provide a tandem transit function in these Agreements, but stated that the crux of the dispute in this case is the rate. Witness Blake also modified her position concerning BellSouth's Section 251 obligations by agreeing that BellSouth had an obligation to provide a tandem transit function based upon the FCC's Virginia arbitration orders and the Commission's September 22, 2003 Order in Docket No. P-19, Sub 454 that found ILECs have an obligation to provide transit service. Witness Blake testified that the TIC is designed to cover not only the cost of sending records identifying the originating carrier, but the "value-added" nature of the service as well. The transit function eliminates the need for originating carriers to directly connect with terminating carriers. The TELRIC tandem rate covers the transit part, while the TIC reflects the value of not having to directly interconnect with carriers.

The Public Staff stated in its Proposed Order that there appears to be no dispute that BellSouth is obligated to provide transit service. Witness Blake acknowledged that the Commission has previously found ILECs have an obligation to provide transit service and that the FCC has found the tandem transit function is a Section 251 obligation. Therefore, the Public Staff believed that the question before the Commission is whether BellSouth should be permitted to charge a TIC in addition to the TELRIC-based tandem switching rate. Although BellSouth has conceded that the tandem transit function is a Section 251 obligation, it is unclear why BellSouth still maintains that this function is not subject to the pricing requirements set forth in

Section 252. The Public Staff noted that the FCC has implemented specific rules to which the Commission must adhere in determining the appropriate rates for providing a tandem transit function.

The Commission can find no basis for permitting BellSouth to impose a TIC for the tandem transit function. The tandem transit function is a Section 251 obligation, and BellSouth must charge TELRIC rates for it. As pointed out by the Commission in its September 22, 2003 Order in Docket No. P-19, Sub 454, the tandem transit function may also involve a billing intermediary function. While this may not be necessary for the parties to this proceeding, the rates for providing a billing intermediary function are not required to be TELRIC-based. The Commission concurs that the tandem transit function provides some value to CLPs by permitting them to avoid directly interconnecting with all of the LECs subtending BellSouth's tandem. However, the fact that CLPs receive value for this service is not grounds for disregarding the FCC's pricing rules.

CONCLUSIONS

The Commission concludes that BellSouth should not be permitted to charge a TIC when providing a tandem transit function for CLPs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

ISSUE NO. 15 - MATRIX ITEM NO. 86(B): How should disputes over alleged unauthorized access to customer service record (CSR) information be handled under the Agreement?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners argued that if one party disputes the other party's assertion of noncompliance regarding access to CSR information, that party should notify the other party in writing of the basis for its assertion of compliance. The Joint Petitioners maintained that if the receiving party fails to provide the other party with notice that appropriate corrective measures have been taken within a reasonable time or fails to provide the other party with proof sufficient to persuade the other party that it erred in asserting the noncompliance, the requesting party should proceed pursuant to the Dispute Resolution provisions set forth in the General Terms and Conditions and the parties should cooperatively seek expedited resolution of the dispute. The Joint Petitioners asserted that "self help", in the form of suspension of access to ordering systems and discontinuance of service, is inappropriate and coercive; moreover, it effectively denies one party the ability to avail itself to the Dispute Resolution process otherwise agreed to by the parties.

BELLSOUTH: BellSouth maintained that the Commission should adopt BellSouth's most recent proposed language for Matrix Item No. 86(b) (if the accused party fails to produce an appropriate letter of authorization (LOA) within the allotted time period, the requesting party will provide written notice via email to a person designated by the other party to receive such notice specifying the alleged noncompliance and advising that access to ordering systems may be suspended in five days if such noncompliance does not cease) as it addresses all of the Joint Petitioners' concerns as well as gives the parties sufficient recourse if a party refuses to comply with its legal and contractual obligations regarding the protection of CSRs.

PUBLIC STAFF: The Public Staff agreed with the Joint Petitioners' position.

DISCUSSION

The Parties disagree on the appropriate language for Sections 2.5.5.2 and 2.5.5.3 of Attachment 6 of the Agreement, as follows:

Section 2.5.5.2 – Joint Petitioners
Notice of Noncompliance. If, after receipt of a requested LOA, the requesting Party determines that the other Party has accessed CSR information without having obtained the proper end user authorization, or, if no LOA is provided by the seventh (7^{th}) business day after such request has been made, the requesting Party will send written notice to the other Party specifying the alleged noncompliance. The Party receiving the notice agrees to acknowledge receipt of the notice as soon as practicable. If the Party receiving the notice does not dispute the other Party's assertion of non-compliance, the receiving Party agrees to provide the other Party with notice that appropriate corrective measures have been taken or will be taken as soon as practicable.

Section 2.5.5.2 – BellSouth
Notice of Noncompliance. If, after receipt of a requested LOA, the requesting Party determines that the other Party has accessed CSR information without having obtained the proper end user authorization, or, if no LOA is provided by the seventh (7^{th}) business day after such request has been made, the requesting Party will send written notice by email to the other Party specifying the alleged noncompliance.

Section 2.5.5.3 – Joint Petitioners
Disputes over Alleged Noncompliance. If one Party disputes the other Party's assertion of non-compliance, that Party shall notify the other Party in writing of the basis for its assertion of compliance. If the receiving Party fails to provide the other Party with notice that appropriate corrective measures have been taken within a reasonable time or provide the other Party with proof sufficient to persuade the other Party that it erred in asserting the non-compliance, the requesting Party shall proceed pursuant to the dispute resolution provisions set forth in the General Terms and Conditions. In such instance, the Parties cooperatively shall seek expedited resolution of the dispute. All such information obtained through the process set forth in this Section 2.5.5 shall be deemed Information covered by the Proprietary and Confidential Information Section in the General Terms and Conditions of this Agreement.

Section 2.5.5.3 – BellSouth
Disputes over Alleged Noncompliance. In it's written notice to the other Party the alleging Party will state that additional applications for service may be refused, that any pending orders for service may not be completed, and/or that access to ordering systems may be suspended if such use is not corrected or ceased by the fifth (5^{th}) calendar day following the date of the notice. In addition, the alleging Party may, at the same time, provide written notice by email to the person designated by the other Party to receive notices of noncompliance that the alleging Party may terminate the provision of access to ordering systems to the other Party and may discontinue the provisioning of existing services if such use is not corrected or ceased by the tenth (10^{th}) calendar day following

the date of the initial notice. If the other Party disagrees with the alleging Party's allegations of unauthorized use, the alleging Party shall proceed pursuant to the dispute resolution provisions set forth in the General Terms and Conditions. All such information obtained through the process set forth in this Section 2.5.5 shall be deemed Information covered by the Proprietary and Confidential Information Section in the General Terms and Conditions of this Agreement.

Joint Petitioners witnesses Collins, Russell, and Falvey stated in prefiled testimony that the Joint Petitioners' position on this issue is that if one party disputes the other party's assertion of noncompliance, that party should notify the other party in writing of the basis for its assertion of compliance. Witnesses Collins, Russell, and Falvey continued that if the receiving party fails to provide the other party with notice that appropriate corrective measures have been taken within a reasonable time or provide the other party with proof sufficient to persuade the other party that it erred in asserting the noncompliance, the requesting party should proceed pursuant to the Dispute Resolution provisions set forth in the General Terms and Conditions and the parties should cooperatively seek expedited resolution of the dispute. Witnesses Collins, Russell, and Falvey maintained that "self help", in the form of suspension of access to ordering systems and discontinuation of service, is inappropriate and coercive; moreover, it effectively denies one party the ability to avail itself of the Dispute Resolution process otherwise agreed to by the parties.

Witnesses Collins, Russell, and Falvey asserted that self help is nearly always an inappropriate means of handling a contract dispute. They maintained that disputes should be handled in accordance with the Dispute Resolution provisions of the contract and not under the threat of suspension of access to operations support systems (OSS) or termination of all services.

Witnesses Collins, Russell, and Falvey stated that BellSouth's proposed language is inadequate because it provides little more than the threat of suspension of access to OSS and the termination of all services regardless of its potential impact on its competition or consumers who have been disloyal to BellSouth. They argued that while BellSouth offers as window dressing that if the CLP disagrees with BellSouth's allegations of unauthorized use, the CLP must proceed pursuant to the dispute resolution provisions set forth in the General Terms and Conditions. However, the witnesses asserted, it is not clear whether BellSouth gets to pull the plug while the dispute is pending or whether the coercive pressure created by BellSouth's ambiguous language is all that it is seeking. Witnesses Collins, Russell, and Falvey maintained that in the end, neither CLPs nor their customers should be forced into such a precarious provision.

Witness Collins agreed on cross-examination that CSR information contains customer proprietary network information (CPNI) and that BellSouth and the Joint Petitioners have an obligation to protect CPNI. Witness Collins further agreed that BellSouth and the Joint Petitioners have decided not to view, copy, or otherwise obtain access to CSR information without the customer's permission. He also agreed that the language proposed by both the Joint Petitioners and BellSouth states that if there is a question about whether either party has obtained a customer's permission, then either party can request the other party to provide an appropriate LOA within seven business days or at least nine calendar days. Witness Collins agreed that under BellSouth's proposed language, if no LOA is provided within seven business days, then the party that made the request will notify the other party that it has five more days to produce the LOA or orders may be suspended or refused. He stated that BellSouth's proposed language is not ambiguous. He agreed that in the Joint Petitioners' proposed language, the other party will provide notice that appropriate corrective measures have been taken or will be taken as soon as practicable. Further, he agreed that, in the Joint Petitioners' proposed language, if the accused party or the offending party simply fails to respond to an assertion that such party is accessing CSR information without permission, then the accusing party has got to look to the dispute resolution provision. Witness Collins also stated that to his knowledge there has not been any prior termination or suspension of service because of unauthorized access to CSR information between BellSouth and KMC. Witness Collins further stated that he could not give one reason why KMC would need more than 14 days to produce a LOA.

Witness Russell stated on cross-examination that BellSouth and NuVox have had only one LOA dispute back in 1998 or 1999 and that the dispute was resolved when NuVox produced a LOA.

Joint Petitioners witness Falvey also testified during the hearing that he was not aware of any dispute within recent years between Xspedius and BellSouth regarding unauthorized access of CSR information. Witness Falvey asserted that the proposed provision is reciprocal but that the reality is that a CLP does not have any services to pull the plug on for BellSouth. He maintained that there are other ways to handle CSR disputes other than a pull-the-plug type measure. Witness Falvey agreed that violation of CPNI rules is a violation of federal law. Witness Falvey stated on cross-examination that this self-help issue is a matter of fundamental fairness and that the parties should go through dispute resolution.

The Joint Petitioners asserted in their Proposed Order that this item is about whether disputes over unauthorized access to CSR information should be excepted from the Agreement's dispute resolution provisions. The Joint Petitioners maintained that both parties agree that CSR information contains CPNI which may not be accessed without a LOA from the customer. The Joint Petitioners argued that BellSouth has proposed a menu of debilitating sanctions it would impose for any allegation by BellSouth of unauthorized access by the Joint Petitioners. The Joint Petitioners argued that under BellSouth's proposal, BellSouth could refuse to accept new orders, suspend any pending orders, and suspend access to ordering and provisioning systems, thus, closing off the Joint Petitioners' ability to serve the needs of existing customers, as well as potential new ones. Ultimately, the Joint Petitioners stated, BellSouth could terminate all services provided to the Joint Petitioners, no matter how unrelated to the unproven allegations of unauthorized access to CSRs. The Joint Petitioners noted that BellSouth witness Morillo conceded on cross-examination that the suspension of access to BellSouth's OSS ordering systems could result in the loss of customers to the Joint Petitioners. The Joint Petitioners argued that the disruption of their business operations from such a sanction is obvious. The Joint Petitioners stated that they have proposed that the offended party first notify the other party of the alleged unauthorized access and that the parties attempt to resolve the matter themselves. If unsuccessful, the Joint Petitioners proposed, they ask that the Agreement's standard dispute resolution provisions apply.

The Joint Petitioners maintained that BellSouth has not met its burden of proof on this item. The Joint Petitioners argued that they can find no evidence to support the inclusion of the self-help remedy BellSouth has proposed and that they find no basis to deviate from the Agreement's standard dispute resolution provision here.

The Joint Petitioners recommended that the Commission conclude that disputes over unauthorized access to CSR information should be resolved by resorting to the standard dispute resolution provisions in the General Terms and Conditions section of the Agreement and that the language offered by BellSouth for this section of the Agreement should not be included.

BellSouth witness Ferguson stated in direct testimony that BellSouth's position is that the party providing notice of the impropriety concerning CSRs should notify the offending party that additional applications for service may be refused, that any pending orders for service may not be completed, and/or that access to ordering systems may be suspended if such use is not corrected or ceased by the fifth calendar day following the date of the notice. In addition, witness Ferguson noted, the alleging party may, at the same time, provide written notice to the person(s) designated by the other party to receive notice of noncompliance that the alleging party may terminate the provision of access to ordering systems to the other party and may discontinue the provisioning of existing services if such use is not corrected or ceased by the tenth calendar day following the date of the initial notice. Witness Ferguson maintained that if the other party disagrees with the alleging party's charges of unauthorized use, the other party should proceed pursuant to the dispute resolution provisions set forth in the General Terms and Conditions of the Agreement.

Witness Ferguson argued that CLPs are well aware that BellSouth does not suspend or terminate access to OSS interfaces on a whim. Witness Ferguson asserted that BellSouth does not suspend or terminate access if there is a good faith dispute between the parties; however, he stated, if circumstances indicate a systemic problem with unauthorized CSR access, then the Joint Petitioners want BellSouth to file a complaint with the Commission, which could take a year or more to resolve. Witness Ferguson maintained that BellSouth's proposed language, on the other hand, balances the Joint Petitioners' right not to be suspended except for good cause versus BellSouth's right not to have to endure protracted proceedings in order to correct the situation of unauthorized access.

Witness Ferguson stated in his summary that if BellSouth has a reason to believe that a CLP is engaged in abusive access to CPNI or is using methods that degrade the network access to that information, and the CLP refuses to acknowledge or cure the abuse, BellSouth must have the leeway to resolve such a situation in as timely a manner as necessary to protect BellSouth's customers, other CLPs, and the other CLPs' customers. He maintained that unless a CLP is engaged in, or is planning to engage in, such fraudulent activity, BellSouth's proposed language should not be a concern. Witness Ferguson noted that there is no evidence to suggest that the Joint Petitioners are predisposed to such activity, and BellSouth is not singling them out with the proposed language. However, witness Ferguson noted, the interconnection agreement signed by the Joint Petitioners and BellSouth could be adopted by other CLPs who are not as concerned with protection of CPNI. He noted that BellSouth has been forced to terminate access for CSR abuse only once to his knowledge in a case of both CPNI violation and access degradation.

Witness Ferguson agreed during cross-examination that BellSouth has proposed a series of sanctions for unauthorized access to CSRs: (1) refusals to accept new orders; (2) suspension of pending orders; and (3) denial of access to the system (i.e., no additional access to the CSR database would be possible). He asserted that it is a BellSouth capability and decision to impose these sanctions. He maintained that this issue is a business-impacting issue for the Joint Petitioners and BellSouth.

BellSouth stated in its Post-Hearing Brief that the crux of this issue is simple: how long does a party need to produce documentation establishing that it has complied with the law by obtaining a customer's authorization to review the customer's records prior to receiving such records? BellSouth commented that as conceded by the Joint Petitioners, two weeks is more than a sufficient amount of time for the parties to demonstrate compliance with their legal and contractual obligations.

BellSouth maintained that the Joint Petitioners conceded that CSR information contains CPNI and that BellSouth and the Joint Petitioners have an obligation under federal law to protect the unauthorized disclosure of CPNI. BellSouth argued that given such obligations, it is no surprise that the parties have agreed to refrain from accessing CSR information without an appropriate LOA from a customer and to access CSR information only in strict compliance with applicable laws. BellSouth stated that regarding LOAs, the parties have agreed that upon request, a party shall use best efforts to provide an appropriate LOA within seven business days.

BellSouth asserted that under its most recent proposed language, if the accused party fails to produce an appropriate LOA within the allotted time period, the requesting party will provide written notice via email to a person designated by the other party to receive such notice specifying the alleged noncompliance and advising that access to ordering systems may be suspended in five days if such noncompliance does not cease. BellSouth further noted that if the accused party disputes the allegations of noncompliance, then the requesting party, prior to suspending or terminating service, would seek an expedited resolution of the CSR dispute from the appropriate regulatory body pursuant to the dispute resolution procedures. BellSouth noted that it offered this revised language during the Georgia hearing in an effort to compromise and address the Joint Petitioners' concerns about buried notices or pull-the-plug provisions. BellSouth stated that despite offering this language almost two months ago, the Joint Petitioners have failed to respond to BellSouth's modified language for Matrix Item No. 86(b).

BellSouth asserted that under its proposal, prior to any action being taken by the requesting party, the accused party has at least two full weeks to exercise best efforts to produce the LOA. BellSouth argued that two weeks is more than sufficient time to produce evidence that the Joint Petitioners are legally and contractually obligated to keep. BellSouth maintained that at the evidentiary hearing, the Joint Petitioners could not articulate one reason why any additional time beyond the two weeks would be needed to produce an appropriate LOA.

Additionally, BellSouth noted, it is unclear why the Joint Petitioners are so adamantly opposed to BellSouth's proposed language given the fact that with one exception, the Joint Petitioners cannot identify any prior disputes regarding unauthorized access to CSR information. BellSouth commented that it recalled one dispute which was immediately resolved when NuVox produced an appropriate LOA.

BellSouth recommended that the Commission adopt BellSouth's most recent proposed language for Matrix Item No. 86(b) as it addresses all of the Joint Petitioners' concerns as well as gives the parties sufficient recourse if a party refuses to comply with its legal and contractual obligations regarding the protection of CSRs.

The Public Staff stated in its Proposed Order that BellSouth's proposed language puts the burden of proof on the CLP. The Public Staff noted that despite BellSouth's assurances that it will not suspend access to ordering and provisioning functions on a whim, its proposed language gives it the discretion to do so. The Public Staff believes that suspension, prior to any dispute resolution process, would place undue pressure on a CLP to acquiesce in order to maintain access to critical ordering and provisioning functions.

The Public Staff agreed with the Joint Petitioners that BellSouth should not be able to unilaterally determine if an alleged case of noncompliance is sufficient to terminate access to its OSS and thereby severely hinder a CLP's ability to serve its customers. The Public Staff maintained that if the parties cannot informally resolve a dispute over noncompliance, the dispute resolution process is the appropriate recourse. Therefore, the Public Staff recommended that the language proposed by the Joint Petitioners for Sections 2.5.5.2 and 2.5.5.3 of Attachment 6 of the Agreement should be adopted since it is fair and equitable to both parties and provides a viable option for settling disputes.

The Commission notes that all of the Parties agree that this issue is a business-impacting issue. Further, all of the Parties agree that violations of CPNI are not allowed based on federal law and that CSR information contains CPNI which may not be accessed without a LOA from the customer.

The substantive difference between the Parties on this issue concerns Section 2.5.5.3 – Disputes Over Noncompliance. Under both the Joint Petitioners' and BellSouth's proposed language in Section 2.5.5.2, a party asserting noncompliance (the alleging party) will notify the other party (the accused party) in writing.

Under the Joint Petitioners' language, if an accused party agrees with the alleged noncompliance, that party should provide notice that corrective measures have been taken as soon as practicable. If the accused party disputes the alleging party's assertion of noncompliance, the accused party would provide proof sufficient to persuade the alleging party that the alleging party erred in asserting noncompliance. If the accused party does not provide either a notice or proof as outlined above, then the alleging party should proceed pursuant to the dispute resolution provisions in the Agreement.

Under BellSouth's language, BellSouth may provide in its notice that additional applications for service may be refused, that any pending orders for service may not be completed, and/or that access to ordering systems may be suspended if such use is not corrected or ceased by the fifth calendar day following the date of the notice. In addition, at the same time, BellSouth may provide written notice by email to the person designated by the accused party to receive notices of noncompliance that the alleging party may terminate the provision of access to ordering systems to the accused party and may discontinue the provisioning of existing services if such use is not corrected or ceased by the tenth calendar day following the date of the initial notice. If an accused party disagrees with the alleged noncompliance, then the alleging party should proceed pursuant to the dispute resolution provisions in the Agreement.

The Commission agrees with the Joint Petitioners that it is unclear from BellSouth's proposed language whether BellSouth gets to pull the plug while a dispute concerning noncompliance is pending. Further, the Commission believes that suspension of access to OSS and the termination of all services is a severe consequence and agrees with the Joint Petitioners and the Public Staff that BellSouth should not be able to unilaterally determine if an alleged case of noncompliance is sufficient to terminate access to OSS. Therefore, the Commission finds it reasonable and appropriate to adopt the Joint Petitioners' proposed language for Sections 2.5.5.2 and 2.5.5.3 of Attachment 6 of the Agreement.

CONCLUSIONS

The Commission concludes that the Joint Petitioners' proposed language concerning how disputes over alleged unauthorized access to CSR information should be handled under the Agreement is reasonable and appropriate. Accordingly, the Commission adopts the Joint Petitioners' proposed language for Sections 2.5.5.2 and 2.5.5.3 of Attachment 6 of the Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

ISSUE NO. 16 - MATRIX ITEM NO. 88: What rate should apply for Service Date Advancement (a/k/a service expedites)?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners argued that the rates for Service Date Advancement (a/k/a service expedites) related to UNEs, interconnection, or collocation should be set consistent with TELRIC pricing principles.

BELLSOUTH: BellSouth maintained that this issue is not appropriate for arbitration under Section 252 of the Act because BellSouth has no Section 251 obligation to expedite service orders.

PUBLIC STAFF: The Public Staff recommended that the Commission conclude that BellSouth must provide service expedites to CLPs at TELRIC rates. The Public Staff further recommended that if, after further negotiation, the parties cannot agree on an appropriate rate, BellSouth should submit a TELRIC cost study for Commission review and approval.

DISCUSSION

This issue concerns Section 2.6.5 of Attachment 6 of the Agreement. The Parties do not disagree on the appropriate language for Section 2.6.5, however they disagree on the appropriate rate.

Joint Petitioners witnesses Collins, Willis, and Falvey asserted in direct testimony that rates for service expedites related to UNEs, interconnection, or collocation should be set consistent with TELRIC pricing principles. They argued that where CLPs require access to UNEs on an expedited basis, which is often necessary in order to meet a customer's needs, CLPs should not be subject to inflated, excessive fees that were not set by the Commission and that do not comport with the TELRIC pricing standard.

Witnesses Collins, Willis, and Falvey maintained that BellSouth's position is that it is not required to provide expedited service pursuant to TA96. Therefore, they stated, BellSouth's proposed language states that BellSouth's tariffed rates for service date advancements will apply;

the tariffed rate is $200.00 per element, per day. They argued that this fee is unreasonable, excessive, and harmful to competition and consumers.

Witnesses Collins, Willis, and Falvey argued that this issue which concerns the manner in which BellSouth provisions UNEs is within the parameters of Section 251. They maintained that setting prices and arbitrating the terms and provisions associated with Section 251 unbundling are squarely within the Commission's jurisdiction and are appropriately resolved in this arbitration proceeding.

In rebuttal testimony, witnesses Collins, Willis, and Falvey maintained that BellSouth witness Morillo did not dispute that UNEs must be provisioned at TELRIC-compliant rates. They argued that an expedite order for a UNE should not be treated any differently. In addressing witness Morillo's claims that BellSouth's expedite charges are set forth in its FCC-approved FCC No. 1 Tariff, which are the same charges that BellSouth charges its retail customers, witnesses Collins, Willis, and Falvey asserted that the Joint Petitioners are not BellSouth retail customers. They stated that the Joint Petitioners purchase UNEs at TELRIC rates, whereas BellSouth retail customers do not. Consequently, they maintained, the corresponding charge to expedite an order for a UNE should also be a TELRIC rate set by the Commission, not the retail rate from BellSouth's FCC tariff.

Witnesses Collins, Willis, and Falvey noted that the dispute is not whether BellSouth will offer expedites in the Agreement since BellSouth has already agreed to do so; they maintained the dispute is over the appropriate rate. Witnesses Collins, Willis, and Falvey stated they are not convinced by witness Morillo's statement that if there were no charge or a minimal charge for expedites, it is likely that most CLP orders would be expedited, causing BellSouth to miss its standard intervals and its obligations to provide nondiscriminatory access. They argued that BellSouth should not be able to set an artificially high service expedite charge in order to keep its expedite ordering volumes at an artificially low level.

Witnesses Collins, Willis, and Falvey maintained that the Joint Petitioners remain optimistic that BellSouth will take them up on their offer to negotiate a reasonable rate for service expedites.

Witness Collins agreed on cross-examination that BellSouth is not obligated to provide service expedites. Witness Collins agreed that a service expedite request is not something unique to the telecom industry. He agreed that if someone wanted to mail a letter via first-class mail, it will cost 37 cents and that if someone wanted to send that same letter via overnight mail, it would cost substantially more than 37 cents. Witness Collins also stated that he could not cite any specific Commission or FCC order that says an expedite should be priced at TELRIC; he asserted that Section 251 of TA96 would require such a result.

Witness Collins also agreed on cross-examination that BellSouth's Service Quality Measurement (SQM)/Self-Effectuating Enforcement Mechanism (SEEM) plan is designed to ensure that BellSouth continues to meet its Section 251 obligations, including its provisioning obligations and that the SQM/SEEM plan contains no provision measurements regarding BellSouth's ability to meet the service expedite request. He asserted that expedites, by nature, do not have a standard interval.

Witness Collins admitted on cross-examination that during his deposition, he stated that he was not aware of any state commission order, federal order, or any other authority for the position that a service expedite charge must be TELRIC based. He further stated that he had learned something since the time of his deposition: that Section 251 requires nondiscrimination. He stated that under Section 251 and nondiscrimination there is a right to a service expedite. When asked whether KMC charges its customers $250.00 for a service expedite, witness Collins stated that he would not be aware of the pricing.

The Joint Petitioners stated in their Proposed Order that TA96 requires that all UNEs be provisioned at rates that comply with TELRIC principles. The Joint Petitioners argued that the Commission is required to ensure that all Section 251 interconnection agreements comply with this standard. The Joint Petitioners maintained that because this issue regards the rates that apply to UNE provisioning, the Commission should find that it has jurisdiction to review it.

The Joint Petitioners stated that the sole dispute with respect to Section 2.6.5 of Attachment 6 of the Agreement is the price that should apply when BellSouth performs Service Date Advancements. The Joint Petitioners maintained that TELRIC principles should apply because Advancements involve UNE provisioning and, thus, are governed by the cost-based pricing of Section 252. Moreover, the Joint Petitioners argued, the work performed is no different than the work required to provision a UNE under a standard interval.

The Joint Petitioners also asserted that the general nondiscrimination requirements of TA96 require BellSouth to perform Service Date Advancements in the same manner as BellSouth performs them for itself. The Joint Petitioners argued that the record demonstrates that BellSouth performs Service Date Advancements for its own retail unit, which then provides the service to its retail customers.

The Joint Petitioners noted that BellSouth's proposed rate for Service Date Advancements is $200.00 per facility, per each day advanced. The Joint Petitioners stated that it is not clear that the wholesale provisioning arm of BellSouth imposes that same requirement on the BellSouth retail division. Thus, the Joint Petitioners stated, although the BellSouth end user customer may pay an expedite fee, the retail entity of BellSouth may not. The Joint Petitioners asserted that this Service Date Advancement fee thus appears to be a cost of doing business for the Joint Petitioners, but not for BellSouth itself.

The Joint Petitioners argued that all UNEs must be priced at cost. The Joint Petitioners noted that the FCC has implemented this mandate with the creation of the TELRIC methodology. In addition, the Joint Petitioners stated, the FCC requires in Rule 51.501 that the methods of obtaining access to unbundled elements must be priced at TELRIC. The Joint Petitioners asserted that a Service Date Advancement is a means of obtaining a UNE and is part and parcel of provisioning a UNE, thus it is included in Congress' cost-based pricing mandate, and thus, TELRIC applies.

The Joint Petitioners maintained that the concepts of nondiscrimination and parity require that BellSouth treat the Joint Petitioners in the same manner as it treats its retail entity. Specifically, the Joint Petitioners commented, BellSouth must provide the same network access to the Joint Petitioners as its retail entity is provided. The Joint Petitioners argued that in this instance, it appears that BellSouth will perform Service Date Advancements for its retail entity without charge, but seeks to impose a $200.00 per facility, per day fee on the Joint Petitioners.

The Joint Petitioners asserted that such a provision would violate the nondiscrimination and parity principles of Section 251.

The Joint Petitioners also argued that this regime would give BellSouth an unfair competitive advantage over the Joint Petitioners. The Joint Petitioners maintained that BellSouth's retail entity would be entitled to request Service Date Advancements at any time, without having to absorb any additional costs. The Joint Petitioners asserted that this result would not serve the public interest, as it would impede the Joint Petitioners' ability to compete in the North Carolina market and meet the needs of the customers it seeks to serve.

The Joint Petitioners noted that although BellSouth has not to date presented any cost justification for the Service Date Advancement fee, it is possible that in the future it may. For example, the Joint Petitioners stated, there may be costs associated with OSS maintenance and order management that are not incorporated in existing UNE provisioning rates. The Joint Petitioners recommended that the Commission review such costs if they are presented to the Commission and order the Joint Petitioners to adopt into the Agreement any TELRIC-compliant rates that the Commission establishes based on the costs.

In conclusion, the Joint Petitioners recommended that the Commission find that the charge for a Service Date Advancement must comport with the general pricing principles set forth in FCC Rule 51.503 and Section 252(d)(1) of TA96. Therefore, the Joint Petitioners recommended that the Commission find that BellSouth may charge only a TELRIC-based Service Date Advancement fee and reject BellSouth's proposed fee. The Joint Petitioners proposed that, in the event that BellSouth presents costing data to demonstrate the additional costs associated with Service Date Advancements, the Commission review them and set rates in accordance with TELRIC methodology that will apply to the Agreement on a going-forward basis after amendment.

BellSouth witness Morillo stated in direct testimony that BellSouth's obligations under Section 251 of TA96 are to provide service in standard intervals at cost-based prices. He maintained that there is no Section 251 requirement that BellSouth provide service in less than the standard interval. Witness Morillo argued that because BellSouth is not required to provide expedited service pursuant to TA96, the Joint Petitioners' request on this issue is not appropriate for a Section 251 arbitration, and it should not, therefore, be included in the Interconnection Agreement. Witness Morillo asserted that if BellSouth elects to offer this service in the Agreement, it should not be penalized for doing so by having TELRIC rates apply to a function that is not even contemplated by the Act.

Witness Morillo noted that BellSouth's expedite charges are set forth in BellSouth's FCC No. 1 Tariff, Section 5. He stated that these are the same charges BellSouth's retail customers are charged when a retail customer requests service in less than the standard interval. Witness Morillo opined that to the extent that a CLP wants expedited service, the CLP should pay the same rates as BellSouth's retail customers. Witness Morillo stated that since BellSouth has no obligation under Section 251 to provide CLPs with expedited service, the cost-based pricing standards of Section 252(d) do not apply. Witness Morillo asserted that BellSouth's position on this issue is reasonable and provides parity of service between how BellSouth treats CLPs and how it treats its own retail customers.

Witness Morillo stated on cross-examination that BellSouth does not have an obligation under TA96 to provide service on an expedited basis. However, he also stated that he was not an attorney so this was not a legal opinion.

Witness Morillo observed that negotiations between the Joint Petitioners and BellSouth on the appropriate charge have not gone "anywhere". He also asserted that pricing expedites at TELRIC would be a penalty since it would force BellSouth to provide service at a price that BellSouth does not think is justifiable and commercially reliable. He stated that he was not aware of any cost studies that BellSouth had done with respect to its actual costs for service expedites.

BellSouth maintained in its Brief that compulsory arbitration under Section 252 of the Act should be properly limited to those issues necessary to implement a Section 251 interconnection agreement. BellSouth argued that expedite charges are not necessary to implement the agreement, especially since BellSouth meets its Section 251 obligations by providing service pursuant to standard provisioning intervals already established by the Commission. Accordingly, BellSouth maintained, the Commission should refrain from arbitrating this issue.

Indeed, BellSouth argued, it has a Section 251 obligation to provision interconnection services and UNEs within standard provisioning intervals. BellSouth asserted that the Commission recognized this obligation in establishing a performance measurement plan (the SQM/SEEM plan) for BellSouth in North Carolina in Docket No. P-100, Sub 133k. BellSouth maintained that the SQM/SEEM plan is designed to ensure that BellSouth continues to meet its Section 251 obligations and requires BellSouth to pay SEEM penalties if BellSouth fails to provision services within such standard intervals. BellSouth further noted that the SQM plan contains 17 provisioning measures which are disaggregated into over 1,200 provisioning sub-measures. BellSouth further noted that, at the evidentiary hearing, the Joint Petitioners conceded that the SQM/SEEM plan contains no expedited provisioning measures. BellSouth asserted that this fact provides conclusive evidence that the expedited provisioning of a service order is a matter that is completely outside the scope of Section 251.

BellSouth commented that further buttressing this conclusion is the fact that the Joint Petitioners concede that BellSouth has no obligation to expedite service orders. Additionally, BellSouth maintained, the Joint Petitioners admit that if a service expedite request cannot be met by BellSouth, the Joint Petitioners can look to alternative measures to satisfy their customers' service request. BellSouth asserted that, clearly, if a service expedite was a Section 251 obligation, the Joint Petitioners would not concede that BellSouth has no obligation to provide it.

BellSouth maintained that with the exception of citing Section 251(c)(3) of the Act, the Joint Petitioners cannot cite any authority that supports their contention that a service expedite request should be priced at TELRIC. BellSouth commented that the words expedite or advancement do not appear in the text of Section 251(c)(3), and instead, BellSouth has, among other things, a nondiscriminatory obligation under Section 251(c)(3). BellSouth asserted that from a provisioning perspective, BellSouth satisfies such obligation by provisioning services within standard intervals and by charging CLPs the same service expedite rate that it charges its retail customers for purchasing services out of BellSouth's access tariff. BellSouth argued that the Joint Petitioners' assertion that they are not retail customers and, thus, should not be charged retail tariff rates misses the mark. BellSouth noted that at the hearing the Joint Petitioners acknowledged that CLPs buy services out of BellSouth's access tariff, such as special access, and when they do, they are charged the rates in the access tariff.

BellSouth stated that, as a practical matter, if there were a TELRIC-based service expedite charge, it is likely that many, if not most, CLP orders would be expedited, thus causing BellSouth to miss its standard intervals and its obligation to provide nondiscriminatory access. BellSouth also maintained that from a policy perspective, any requirement that forces BellSouth to price voluntarily-offered services at TELRIC prices will chill BellSouth's willingness to voluntarily offer services to CLPs.

BellSouth also argued that the special expedite rate reflects the value of the special expedite service being provided, and is no different from choosing to pay in excess of $10.00 to send a letter via overnight rather than paying 37 cents to send the same letter via first class mail. BellSouth asserted that at the evidentiary hearing the Joint Petitioners admitted that special pricing should govern special provisioning requests.

BellSouth concluded that the Commission should refrain from setting rates for voluntarily-offered services and should adopt BellSouth's position on Matrix Item No. 88, as it is reasonable and nondiscriminatory.

The Public Staff noted in its Proposed Order that FCC Rule 51.311(b) provides that if technically feasible an ILEC should provide a CLP with access to UNEs at least equal in quality to that which the ILEC provides to itself. The Public Staff stated that it believes that expediting service to customers is simply one method in which BellSouth can provide access to unbundled network elements. The Public Staff maintained that since BellSouth offers service expedites to its retail customers, it must provide service expedites at TELRIC rates pursuant to Section 251 and Rule 51.311(b).

The Public Staff argued that the rate BellSouth proposes is the rate it charges its large retail customers, but there is no cost support for this rate. Thus, the Public Staff maintained, it is unable to determine whether the rate is TELRIC compliant. The Public Staff stated that it believes that service expedites have costs not reflected in the normal nonrecurring charges for UNE installations, so a TELRIC cost study would likely show higher rates for service expedites than normal service installations. The Public Staff recommended that if the parties cannot come to agreement on a rate for service expedites, BellSouth should submit a TELRIC cost study for the Commission's review and approval.

Overall, the Public Staff recommended that the Commission conclude that BellSouth must provide service expedites to CLPs at TELRIC rates. Further, the Public Staff recommended, if the parties cannot agree on an appropriate rate, BellSouth should submit a TELRIC cost study for Commission review and approval.

The Commission notes that Section 251(c)((3) of the Act states that telecommunications carriers must provide ". . . nondiscriminatory access to network elements on an unbundled basis at any technically feasible point on rates, terms, and conditions that are just, reasonable, and nondiscriminatory in accordance with the terms and conditions of the agreement and the requirements of this section and section 252."

The Commission also notes that FCC Rule 51.311(b) states:

> To the extent technically feasible, the quality of an unbundled network element, as well as the quality of the access to such unbundled network element, that an incumbent LEC provides to a requesting telecommunications carrier shall be at least equal in quality to that which the incumbent LEC provides to itself. If an incumbent LEC fails to meet this requirement, the incumbent LEC must prove to the state commission that it is not technically feasible to provide the requested unbundled network element, or to provide access to the requested unbundled network element, at a level of quality that is equal to that which the incumbent LEC provides to itself.

Although Joint Petitioners witness Collins agreed on cross-examination that BellSouth is not required to provide service expedites, the Commission agrees with the Public Staff that since BellSouth offers service expedites to its retail customers, it must provide service expedites at TELRIC rates pursuant to Section 251 and Rule 51.311(b) to the Joint Petitioners. This outcome is necessary in order to assure that BellSouth provides nondiscriminatory access to UNEs and does so at least equal in quality to that which BellSouth provides itself.

Further, the Commission notes that Joint Petitioners witnesses Collins, Willis, and Falvey maintained that they remained optimistic that BellSouth would take them up on their offer to negotiate a reasonable rate for expedites. The Commission finds it appropriate to require the Joint Petitioners and BellSouth to make a good faith effort to negotiate an appropriate rate for service expedites. If the parties are unable to negotiate a rate, BellSouth should submit a TELRIC cost study for the Commission's review and approval.

CONCLUSIONS

The Commission concludes that BellSouth must provide service expedites at TELRIC-compliant rates. BellSouth and the Joint Petitioners are instructed to negotiate in good faith an appropriate rate for service expedites. If the parties are unable to negotiate a rate, BellSouth should submit a TELRIC cost study for the Commission's review and approval.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

ISSUE NO. 17 - MATRIX ITEM NO. 97: When should payment of charges for service be due?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners recommended that the Commission conclude that payment of charges for services rendered should be due thirty (30) calendar days from receipt or website posting of a complete and fully readable bill or within thirty (30) calendar days from receipt or website posting of a corrected or retransmitted bill in those cases where correction or retransmission is necessary for processing.

BELLSOUTH: BellSouth maintained that payment for services should be made on or before the payment due date (i.e., the next bill date) in immediately available funds.

PUBLIC STAFF: The Public Staff recommended that the Commission conclude that the payment due date should be 26 days from the date of receipt of the bill.

DISCUSSION

The Parties disagree on the appropriate language for Section 1.4 of Attachment 7 of the Agreement, as follows:

Section 1.4 – Joint Petitioners
Payment Due. Payment of charges for services rendered will be due thirty (30) calendar days from receipt or website posting of a complete and fully readable bill or within thirty (30) calendar days from receipt or website posting of a corrected or retransmitted bill in those cases where correction or retransmission is necessary for processing and is payable in immediately available funds. Payment is considered to have been made when received by the billing party.

Section 1.4 – BellSouth
Payment Due. Payment for services will be due on or before the next bill date (Payment Due Date) and is payable in immediately available funds. Payment is considered to have been made when received by the billing Party.

Joint Petitioners witnesses Johnson, Russell, and Falvey stated in direct testimony that payment for charges for services rendered should be due 30 calendar days from receipt or website posting of a complete and fully readable bill or within 30 calendar days from receipt or website posting of a corrected or retransmitted bill in those cases where correction or retransmission is necessary for processing. They argued that the Joint Petitioners need at least 30 days to review and pay invoices. Witnesses Johnson, Russell, and Falvey maintained that in other commercial settings in which parties have established business relationships, the payor may be afforded 45 days or more to pay an invoice. Furthermore, they asserted, it is not uncommon for parties to a contract to develop a course of dealings in which a party is not strictly held to a certain payment date. Nevertheless, witnesses Johnson, Russell, and Falvey stated, in order to try to settle as many billing issues as possible, the Joint Petitioners have agreed to BellSouth's proposal for a 30-day payment deadline (one billing cycle).

Witnesses Johnson, Russell, and Falvey maintained that it is the Joint Petitioners' experience that BellSouth is consistently untimely in posting or delivering its bills and those bills are often incomplete and sometimes incomprehensible. Therefore, the witnesses asserted, in effect BellSouth is actually giving the Joint Petitioners far fewer than 30 days to pay invoices, which is neither typical nor acceptable in a commercial setting, especially in this case, where the bills are numerous, voluminous, and complex.

Witness Russell stated that NuVox has tracked how long it takes BellSouth to post or deliver its bills. He asserted that on average it takes seven days after the issue date for NuVox to receive a bill from BellSouth. Witness Russell also noted that NuVox conducted a study of how long it takes NuVox to receive an electronic invoice from BellSouth using July 2002 through July 2003 data. He stated that although the times recorded by NuVox varied from three days to over 30 days, the average time it takes BellSouth to deliver its electronic bills to NuVox is seven days.

Witness Falvey stated that he has tracked the difference between the date BellSouth posts on the bill and the date the bill is received by Xspedius. He noted that Xspedius began tracking this data in December 2003 and that their results demonstrate that it takes on average 6.45 days for Xspedius to receive a bill from BellSouth. He stated that although the average time is 6.45 days, they have traced bills that Xspedius has received from BellSouth in as little as two days and as long as 22 days.

Witness Russell stated that NewSouth's experience has been that, by the time it receives its bills from BellSouth, it has anywhere from 19 to 22 days to process bills for payment. He asserted that this amount of time is inadequate as it does not allow NewSouth to effectively and completely review and audit the bills it receives from BellSouth.

Witnesses Johnson, Russell, and Falvey stated that BellSouth's proposed language is inadequate since it provides that payment of charges for services rendered must be made on or before the next bill date. They argued that this language does not account for the fact that there is typically a long gap between the time a bill is issued and the date upon which it is made available to or delivered to a Joint Petitioner. Witnesses Johnson, Russell, and Falvey asserted that BellSouth's language also makes no attempt to mitigate the problems caused in circumstances when BellSouth's invoices are incomplete and/or incomprehensible.

Witnesses Johnson, Russell, and Falvey maintained that BellSouth is, in essence, using its monopoly legacy and bargaining position to force CLPs to either remit payment faster than almost any other business or in the alternative face substantial late payment penalties and increased security deposits.

Witnesses Johnson, Russell, and Falvey stated in rebuttal testimony that the Joint Petitioners should not be subject to unfair payment terms based on BellSouth's alleged systems limitations. They asserted that BellSouth makes two blanket statements with no justification: (1) due date requirements listed in its access tariff and contracts cannot be differentiated; and (2) all customer due dates and treatments are the same for all customers and cannot be differentiated. Witnesses Johnson, Russell, and Falvey maintained that neither assertion seems to be a valid reason for not providing the Joint Petitioners with reasonable payment terms.

Witnesses Johnson, Russell, and Falvey argued that the Joint Petitioners should not have to endure inconsistent and unfair payment terms because BellSouth would have to undertake modifications to make system changes to fix its systems to allow CLPs adequate time to pay invoices. They maintained that it is unreasonable for BellSouth to assert that its systems cannot be modified and improved or that it won't modify or improve them. Witnesses Johnson, Russell, and Falvey asserted that their request is reasonable, and BellSouth should not be able to hide behind its convenient systems limitations arguments to avoid agreement on reasonable and fair payment terms.

Witnesses Johnson, Russell, and Falvey maintained that BellSouth's argument that it has no way to know when the customer actually receives the bill, thus it is not reasonable to expect that treatment could be based upon the date the customer receives the bill, is not persuasive. They asserted that there is no reason why BellSouth should not be aware when it sends and a customer receives an electronic or paper bill. Witnesses Johnson, Russell, and Falvey stated that it is easy to track on-line posting and receipt of mail – electronic and traditional. They noted that such posting and return receipt functions are basic components of internet-posting and electronic mail programs. They noted that courier services, such as UPS and FedEx, and the United States Postal Service have long provided return receipt or delivery confirmation services to their customers. They stated that it is surprising to them that BellSouth witness Morillo is unaware of such things and that nobody at BellSouth who reviewed his testimony bothered to point them out to him. Witnesses Johnson, Russell, and Falvey stated that because posting and receipt are easily tracked, it is certainly reasonable to tie payment due dates to the posting or receipt of bills.

Witness Russell stated in his summary that the Joint Petitioners were willing to accept the Commission's decision on due dates in the ITC^DeltaCom Communications, Inc. (ITC^DeltaCom)/BellSouth arbitration (Docket No. P-500, Sub 18) (i.e., 26 days after delivery of bill).

On cross-examination, witness Russell stated that during NuVox's seven years in existence it has paid all of its BellSouth invoices in a timely manner. He also stated that NuVox receives certain bills electronically. Witness Russell noted that NuVox's experience demonstrates that they usually receive bills from BellSouth six or seven days after the date posted on the bill. He agreed that BellSouth has incentive from the performance measurement plan perspective to deliver bills in a timely manner. Witness Russell stated that NuVox speaks to its BellSouth account representative on a regular basis about billing disputes, inaccuracies, and failure to deliver bills on time.

Witness Johnson stated on cross-examination that KMC receives most of its BellSouth bills electronically and that KMC receives its BellSouth bills in an average of about seven days.

Witness Falvey stated on cross-examination that Xspedius did a bill study that concluded that Xspedius receives all of its invoices from BellSouth in 6.45 days. He stated that while 30 days is the standard for good bills, given that the Joint Petitioners have problems with BellSouth in terms of the timing of bills and readability and intelligibility of the bills, the Joint Petitioners are asking for the Commission to allow the Joint Petitioners 30 days from the receipt of the bill to make sure they have enough time to go through the bills. He also agreed that if Xspedius found a bill to be confusing it could invoke the dispute resolution provision of the Agreement; however, he asserted it takes a lot of time and energy and resources to invoke the dispute resolution provision. He also commented that Xspedius finds a fair amount of error in the bills.

On redirect, witness Russell stated that when BellSouth delivers a late bill to NuVox, it does not trigger a SEEM penalty payment on its on accord. He noted that SEEM penalties are based on an aggregate of BellSouth's performance and BellSouth's performance with regard to a number of metrics. He stated that simply because BellSouth delivers a bill late to NuVox does not necessarily trigger a SEEM payment directly to NuVox.

The Joint Petitioners stated in their Proposed Order that they recommend that Section 1.4 of Attachment 7 of the Agreement provide for payment of charges for services be due 30 calendar days from receipt or posting of a complete and fully readable bill. The Joint Petitioners noted that BellSouth proposed that payment be due on or before the next bill date in immediately available funds.

The Joint Petitioners noted that their witnesses testified that the Joint Petitioners: (1) receive a large number of bills from BellSouth monthly which are voluminous and complex; (2) these bills are often incomplete and sometimes incomprehensible; and (3) that there is often a long gap between the bill issue date and the date the BellSouth bill is actually posted or received by the Joint Petitioners. The Joint Petitioners stated that there was testimony that the Joint Petitioners do not receive their electronic bills from BellSouth for periods ranging from three to 30 days. The Joint Petitioners further maintained that their witnesses testified that it often takes several weeks to review the BellSouth bills because of their volume and complexity. The Joint Petitioners noted that BellSouth witness Morillo testified that BellSouth pays the bills it receives from the Joint Petitioners on receipt.

The Joint Petitioners maintained that the issue presented in this item is one familiar to the Commission. The Joint Petitioners noted that the same issue was presented in the last ITC^DeltaCom arbitration with BellSouth. The Joint Petitioners argued that nothing in the record of this arbitration gives the Commission a reason to change its decision on this issue. The Joint Petitioners stated that the evidence in this arbitration regarding the lag time between BellSouth's bill date and the issuance of its bills is consistent with the evidence in the ITC^DeltaCom/BellSouth arbitration. The Joint Petitioners recommended that the Commission find that a payment due date 26 days from the date of receipt is a reasonable interval within which the Joint Petitioners can review and pay their bills. The Joint Petitioners noted that as in the ITC^DeltaCom/BellSouth arbitration, the Commission should recognize that special circumstances may warrant an extension of the payment due date beyond this 26-day interval. The Joint Petitioners recommended that the Commission find that it expects BellSouth to grant such requests when reasonable. Finally, the Joint Petitioners noted that in the Joint Issues/Open Items Matrix, they stated that they would find the result in the ITC^DeltaCom/BellSouth arbitration on this issue acceptable.

The Joint Petitioners recommended that the Commission conclude that the payment due date should be 26 days from the date of receipt of the bill, and therefore, require the Joint Petitioners and BellSouth to amend the proposed language in Attachment 7 of the Agreement to conform to this decision.

BellSouth witness Morillo stated in his testimony that BellSouth's position on this issue is that payment for services should be due on or before the next bill date in immediately available funds. He stated that BellSouth has no way to know when a customer actually receives a bill, and thus, it is not reasonable to expect that treatment could be based upon the date the customer receives the bill.

Witness Morillo asserted that there is no legitimate reason to allow the Joint Petitioners a full 30 calendar days after receiving a bill to make payment. He noted that BellSouth invoices each CLP every 30 days, just as it does for its retail customers. He stated that the bill date is the same each month and each CLP is aware of its billing due date. Witness Morillo maintained that a CLP can elect to receive its bills electronically so as to minimize any delay in bill printing and receipt. He also asserted that to the extent a CLP has questions about its bills, BellSouth cooperates with that CLP to provide responses in a prompt manner and resolve any issue. Witness Morillo also noted that in a given month if special circumstances warrant a CLP may request an extension of the due date and BellSouth does not unreasonably refuse to grant such a request.

Witness Morillo explained that from the time an electronic bill goes out, generally four to six days after the bill period, the CLP generally has 22 days to review and pay its bill. He noted that paper bills will take longer. Witness Morillo also asserted that, regarding the Joint Petitioners' allegation of incomplete and/or incomprehensible bills, the CLPs do not support this allegation with examples or other factual evidence. He stated that if the CLPs would provide such evidence, BellSouth would be glad to investigate.

On cross-examination, witness Morillo agreed that BellSouth believes that payment should be due on or before the next bill date and the Joint Petitioners believe that the payment should be due 30 calendar days from the receipt of the bill or the website posting of an electronic bill.

Witness Morillo also agreed that he testified in his deposition that the Joint Petitioners all received electronic bills and that an electronic bill has a confirmation. He agreed that BellSouth pays bills from Xspedius, NuVox, and KMC within 30 days of receipt.

Addressing the decision in the ITC^DeltaCom/BellSouth arbitration, witness Morillo stated that BellSouth's policy remains to have the right to request a 30-day payment cycle. He stated that it is cumbersome for BellSouth to change all of its billing systems just to address three CLPs in North Carolina. He stated that BellSouth is unwilling to accept the Commission's decision in the ITC^DeltaCom/BellSouth arbitration.

BellSouth argued in its Brief that the Joint Petitioners (like all CLPs that do business with BellSouth) have a set and constant bill issuance date for every invoice or bill that the Joint Petitioners receive. BellSouth noted that based on the bill date, the Joint Petitioners know the exact date when payment is due for each bill (i.e., it is by the next bill issuance date). For example, BellSouth stated, a NuVox invoice that is dated the 5th day of the month will always be dated the 5th day of the month and will always be due by the 5th day of the following month.

BellSouth asserted that in addition to knowing when their bills are due, the Joint Petitioners concede, as they must, that their monthly billings are reasonably predictable and that the Joint Petitioners are in the best position to predict or estimate their monthly billings. Further, BellSouth noted, NuVox unequivocally admitted during the evidentiary hearing to paying all of its BellSouth bills in a timely manner for seven years. BellSouth asserted that NuVox's uncontradicted testimony belies the Joint Petitioners' assertion that they need at least 30 days to review and pay their bills.

BellSouth also argued that it is difficult to reconcile the Joint Petitioners' own tariffs with their assertion that BellSouth's payment terms would be considered unacceptable in most commercial settings. BellSouth maintained that the Joint Petitioners' own end user tariffs or standard contract terms require North Carolina customers to pay on or before the payment due date.

BellSouth maintained that the Joint Petitioners' suggestion that, in BellSouth's testimony, BellSouth measured payment of bills received from the Joint Petitioners from the date of receipt is both irrelevant and a mischaracterization of BellSouth's testimony. BellSouth argued that it used the date it received the bills to provide a meaningful way to measure its payment history with the Joint Petitioners because certain Joint Petitioners have not been able to and presently cannot provide BellSouth with a timely bill. BellSouth maintained that the Joint Petitioners do not have the same concerns with bills they receive from BellSouth.

BellSouth argued that granting special payment terms to the Joint Petitioners is also contrary to the Act. Specifically, BellSouth maintained, under Section 251(c), BellSouth has, among other things, an obligation to provide interconnection services and UNEs on rates, terms, and conditions that are just, reasonable, and nondiscriminatory. BellSouth noted that for billing purposes, BellSouth satisfies its nondiscrimination obligations by delivering bills to CLPs in the same time and manner that BellSouth delivers bills to its own retail customers. Additionally, BellSouth stated, it pays SEEM penalties if it fails to deliver CLP bills in a timely manner (i.e., at parity with the time it takes BellSouth to deliver bills to its retail customers). BellSouth noted that as Joint Petitioners witness Russell acknowledged on cross-examination at the evidentiary hearing, from a timeliness perspective, BellSouth has at least two practical reasons (getting paid and avoiding SEEM penalties) for delivering bills to CLPs as soon as possible.

BellSouth asserted that to minimize any delay in receiving its bills, the Joint Petitioners can elect to receive their bills electronically. Indeed, BellSouth maintained, the Joint Petitioners receive bills electronically. BellSouth noted that, further, if any Joint Petitioner has billing questions, nothing precludes the Joint Petitioner from contacting BellSouth with such questions, and BellSouth will respond in a prompt manner. BellSouth asserted that Joint Petitioners witness Russell admitted that NuVox speaks with its BellSouth account representatives on a regular basis regarding billing matters. BellSouth noted that, additionally, Joint Petitioners witness Falvey admitted during the evidentiary hearing that nothing prevents the Joint Petitioners from exercising their rights under the agreed upon billing dispute resolution provision, if any Joint Petitioner receives a bill that appears incomplete or confusing.

BellSouth argued that it is reasonable for BellSouth to expect that payment will be made by the next bill date; BellSouth expects the same from its retail customers. Moreover, BellSouth maintained, if special circumstances warrant, a Joint Petitioner may request an extension of the payment due date, and BellSouth does not unreasonably refuse to grant such a request.

Finally, BellSouth asserted, the Joint Petitioners' proposal would result in an ever extending, revolving payment due date. BellSouth stated that, additionally, granting the Joint Petitioners' request for special payment terms would require modifications to BellSouth's billing systems and would involve substantial costs. BellSouth argued that incurring such costs to meet the special payment due date request of the Joint Petitioners is unnecessary and unwarranted given the fact that in granting BellSouth long distance authority in North Carolina, both the Commission and the FCC determined that BellSouth's billing practices are nondiscriminatory. BellSouth concluded that it has already been determined that BellSouth's existing billing practices give CLPs a meaningful opportunity to compete in the local market; accordingly, the Commission should reject the Joint Petitioners' request for special treatment and adopt BellSouth's proposed language on Matrix Item No. 97.

The Public Staff stated in its Proposed Order that the Commission, in its *March 2, 2004 Order* in Docket No. P-500, Sub 18 – the ITC^DeltaCom/BellSouth arbitration docket, agreed with the Public Staff's recommendation that a payment due date of 26 days from the date of receipt would be an appropriate amount of time. The Public Staff maintained that it had contended that this period represented the approximate amount of time a CLP has to review bills when BellSouth's billing systems are performing adequately and would allow adequate time for review of the bill as well as provide an incentive for BellSouth to render timely bills. The Public Staff noted that the Joint Petitioners indicate that they are willing to accept a payment due date of 26 days from receipt of a bill and this finding from Docket No. P-500, Sub 18 is reasonable and applicable to this proceeding as well. The Public Staff recommended that the Commission conclude that the payment due date should be 26 days from the date of receipt of the bill.

The Commission notes that in its *March 2, 2004 Recommended Arbitration Order* in the ITC^DeltaCom/BellSouth arbitration docket, the Commission stated

> Based upon the foregoing, the Commission believes that the Public Staff's recommendation for the payment due date to be 26 days from the date of receipt is a reasonable interval of time in which ITC can review and pay its bills. In consideration that after the bill date, BellSouth then has to accumulate the traffic sensitive-type charges which according to BellSouth results in another three to five days before bills are electronically transmitted to ITC, which results in ITC typically having a payment due date that is 27 to 25 days after the date of receipt, or sometimes 23 days as ITC noted that it has even been seven days after the bill date before the bill is received, the Commission believes that establishing a specific payment due date of 26 days after receipt of the bill would be reasonable and fair to both ITC and BellSouth. The Commission infers from BellSouth's representation of its present process of a three- to five-day lag, that BellSouth is already rending its bills electronically to ITC, on average, within four days after the bill date, thus, the Commission does not believe that a 26-day requirement would result in any material system-wide change in BellSouth's billing systems. Furthermore, the Commission recognizes that when special circumstances warrant, ITC may request an extension of the payment due date; the Commission believes BellSouth should continue to grant such request, when reasonable.

The Commission further notes that BellSouth filed an Objection to this finding in the Commission's *March 2, 2004 Order*, however, by letter filed May 17, 2004, ITC^DeltaCom stated that it and BellSouth had successfully resolved the issue.

The Commission agrees with the Joint Petitioners and the Public Staff that the Commission's decision in the ITC^DeltaCom/BellSouth arbitration proceeding is reasonable and applicable to this proceeding as well. The Commission does not believe that BellSouth provided any compelling arguments why a 26-day billing period is not appropriate in this docket. Therefore, the Commission concludes that the payment due date should be 26 days from the date of receipt of the bill.

CONCLUSIONS

The Commission concludes that the payment due date should be 26 days from the date of receipt of the bill. Accordingly, the Commission requires the Joint Petitioners and BellSouth to properly amend the proposed language in the Agreement in Attachment 7, Section 1.4, in accordance with this decision.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

ISSUE NO. 18 - MATRIX ITEM NO. 100:

Joint Petitioners' Issue Statement: Should a CLP be required to calculate and pay past due amounts in addition to those specified in BellSouth's notice of suspension or termination for nonpayment in order to avoid suspension or termination?

BellSouth's Issue Statement: Should a CLP be required to pay past due amounts in addition to those specified in BellSouth's notice of suspension or termination for nonpayment in order to avoid suspension or termination?

POSITIONS OF PARTIES

JOINT PETITIONERS: The Joint Petitioners stated that CLPs should not be required to calculate and pay past due amounts in addition to those specified in BellSouth's notice of suspension or termination for nonpayment in order to avoid suspension or termination. Rather, the Joint Petitioners noted, if a CLP receives a notice of suspension or termination from BellSouth, with a limited time to pay nondisputed past due amounts, a CLP should be required to pay only those amounts past due as of the date of the notice and as expressly and plainly indicated on the notice, in order to avoid suspension or termination. Otherwise, the Joint Petitioners maintained, a CLP will risk suspension or termination due to possible calculation and timing errors or the inability to predict posting of payment by BellSouth correctly.

BELLSOUTH: BellSouth maintained that the Commission should continue to allow BellSouth to protect its financial interest by allowing BellSouth to discontinue providing service to any Joint Petitioner that fails to timely pay for services rendered and therefore, should adopt BellSouth's proposed language on Matrix Item No. 100.

PUBLIC STAFF: The Public Staff agreed with the Joint Petitioners' position.

DISCUSSION

The Parties disagree on the appropriate language for Section 1.7.2 of Attachment 7 of the Agreement, as follows:

> **Section 1.7.2 – Joint Petitioners**
> Each Party reserves the right to suspend or terminate service for nonpayment. If payment of amounts not subject to a billing dispute, as described in Section 2, is not received by the Due Date, the billing Party may provide written notice to the other Party that additional applications for service may be refused, that any pending orders for service may not be completed, and/or that access to ordering systems may be suspended if payment of such amounts, as indicated on the notice in dollars and cents, is not received by the fifteenth (15^{th}) calendar day following the date of the notice. In addition, the billing Party may, at the same time, provide written notice that the billing Party may discontinue the provision of existing services to the other Party if payment of such amounts, as indicated on the notice (in dollars and cents), is not received by the thirtieth (30^{th}) calendar day following the date of the Initial Notice.

Section 1.7.2 – BellSouth

BellSouth reserves the right to suspend or terminate service for nonpayment. If payment of amounts not subject to a billing dispute, as described in Section 2, is not received by the bill date in the month after the original bill date, BellSouth will provide written notice to <<customer_short_name>> that additional applications for service may be refused, that any pending orders for service may not be completed, and/or that access to ordering systems may be suspended if payment of such amounts, and all other amounts not in dispute that become past due subsequent to the issuance of the written notice ("Additional Amounts Owed"), is not received by the (15th) calendar day following the date of the notice. In addition, BellSouth may, at the same time, provide written notice that BellSouth may discontinue the provision of existing services to <<customer_short_name>> if payment of such amounts, and all other Additional Amounts Owed that become past due subsequent to the issuance of the written notice, is not received by the thirtieth (30th) calendar day following the date of the initial notice. Upon request, BellSouth will provide information to <<customer_short_name>> of the Additional Amounts Owed that must be paid prior to the time periods set forth in the written notice to avoid suspension of access to ordering systems or discontinuance of the provision of existing services as set forth in the initial written notice.

Joint Petitioners witnesses Johnson, Russell, and Falvey stated in direct testimony that it is their position that CLPs should not be required to calculate and pay past due amounts in addition to those specified in BellSouth's notice of suspension or termination for nonpayment in order to avoid suspension or termination. Rather, they asserted, if a CLP receives a notice of suspension or termination from BellSouth, with a limited time to pay nondisputed past due amounts, CLPs should be required to pay only those amounts past due as of the date of the notice and as expressly and plainly indicated on the notice in order to avoid suspension or termination; otherwise, a CLP will risk suspension or termination due to possible calculation and timing errors.

Witnesses Johnson, Russell, and Falvey asserted that if a Joint Petitioner receives a notice of suspension or termination from BellSouth, it will be the Joint Petitioner's immediate goal to pay the past due amounts included in the notice to avoid suspension or termination. They argued that if the Joint Petitioner must attempt to calculate and pay past due amounts in addition to those specified in BellSouth's notice, the Joint Petitioner unfairly will risk suspension or termination due to possible calculation and timing errors.

Witnesses Johnson, Russell, and Falvey explained that if one of their companies received a notice of suspension or termination from BellSouth, it would be nothing less than a "fire drill". They stated that whoever received the notice would immediately work to determine whether such payments were missing, not posted, disputed, or simply due and, in the latter case, would arrange to deliver payment to BellSouth as fast as possible. Witnesses Johnson, Russell, and Falvey asserted that access to BellSouth's OSS is essential to the daily operation of a CLP and that they take the threat of suspension of such access very seriously as it would result in massive service outages across their North Carolina customer base.

Witnesses Johnson, Russell, and Falvey asserted that any time or resources that they would have to expend in trying to calculate any possible additional past due amounts that may become past due in the time period between the date on which BellSouth calculated the past due amount (which may or may not be known) and the date on which BellSouth would receive and post payment would be taken away from time needed to investigate and secure payment of the amount specified on the suspension or termination notice. But, they maintained, the more significant hindrance is the shell game that would ensue if the Joint Petitioner had to guess the precise amount that BellSouth calculated upon receipt and posting or payment that was needed to satisfy the payment of all amounts past due requirement BellSouth seeks to impose. Witnesses Johnson, Russell, and Falvey noted that under the circumstance, only BellSouth can know (and control) the answer to that calculation, as it knows the date upon which it first calculated the past due amount included in the notice and the date upon which it posts receipt of payment.

Witnesses Johnson, Russell, and Falvey stated that BellSouth's proposed language is inadequate because it places too much burden and risk on the Joint Petitioners who are forced to calculate possible past due amounts in addition to those included in the BellSouth notice to avoid suspension or termination of service. They maintained that BellSouth's proposal amounts to a high stakes shell game that could result in massive service outages for their North Carolina customers, if they fail to properly track, time, trace, and predict BellSouth behavior in a manner that allows them to arrive at a magic number needed to avoid suspension or termination. They argued that such terms and conditions are unreasonable in any setting and especially in this one where consumers' services hang in the balance.

Finally, witnesses Johnson, Russell, and Falvey stated that they disagree with BellSouth's proposed restatement of the issue as it ignores the critical aspect of the issue which is the danger that there could be a calculation error based on erroneous assumptions regarding timing, posted disputes, or some other factors.

In rebuttal testimony, witnesses Johnson, Russell, and Falvey stated that the Joint Petitioners' proposed language is appropriate because there is a substantial risk of calculation errors or disputes and customer impacting service outages inherent in BellSouth's proposal. They argued that BellSouth's proposal is too dangerous to be necessary and it seems intentionally designed to be that way. Witnesses Johnson, Russell, and Falvey maintained that the Joint Petitioners' proposal represents a reasonable and fair alternative that protects the interests of all parties, is not subject to abuse, and does not unduly threaten North Carolina customers' services.

During his summary, witness Russell stated that Matrix Item No. 100 is another provision in which BellSouth threatens to pull the plug on the Joint Petitioners and their North Carolina customers. Witness Russell stated that BellSouth is seeking to contractualize a shell game of sorts wherein it can terminate services if CLPs do not properly calculate time payment and predict BellSouth's own posting of payment amounts due in addition to those set forth on any late payment termination notice.

The Joint Petitioners stated in their Proposed Order that BellSouth, in its proposed language for Section 1.7.2 of Attachment 7, seeks the right to suspend or terminate a Joint Petitioner's service if they fail, after receiving a notice of suspension for nonpayment, to pay the amount due on the notice and any other amounts that may become past due after the date of the notice. The Joint Petitioners noted that, thus, if one account held by a Joint Petitioner is not paid within 31 days on the date of an invoice, the Joint Petitioner must within 15 days pay that amount, plus any other amount that may become late (which will not appear on the notice) within 15 days, in order to avoid suspension of ordering access. The Joint Petitioners commented that failure to pay all amounts within 30 days may result in outright termination of service.

The Joint Petitioners stated that their proposed language for Section 1.7.2 also requires them to remain current on invoices and includes provisions for suspension or termination of service, but requires that any notice state exactly the amount due in dollars and cents that must be paid. The Joint Petitioners noted that their proposed language contains the same deadlines proposed by BellSouth: failure to pay the amount due within 15 days may result in order suspension, and failure to pay within 30 days may result in service termination.

The Joint Petitioners noted that each of them hold many accounts with BellSouth. The Joint Petitioners maintained that each account, if not paid in 31 days, automatically generates a notice. The Joint Petitioners commented that BellSouth witness Morillo testified that any one notice will only state the amount due on the one account from which it is issued. The Joint Petitioners noted that the Joint Petitioner must then pay the amount on the notice, plus any additional amounts that have become past due, in order to avoid suspension or termination of services. The Joint Petitioners maintained that amounts due will not be consolidated in the notice. The Joint Petitioners argued that this situation requires them to calculate for themselves the exact amount due on any given date, and pay it promptly to avoid losing service. Yet BellSouth, the Joint Petitioners argued, as the creditor on all of these accounts, has the ability to calculate the amounts that it is owed.

The Joint Petitioners maintained that service termination is an extremely serious matter. The Joint Petitioners commented that carriers are prohibited by statute from terminating service to customers without the approval of the Commission or the FCC. The Joint Petitioners argued that if BellSouth terminates their service, then North Carolina consumers will necessarily lose service. The Joint Petitioners asserted that the Commission cannot give BellSouth the discretion to impose this penalty when it places on the Joint Petitioners the onus of calculating the amount on the notice, plus any additional amounts that have become past due. The Joint Petitioners argued that this burden is unfair and carries too great of a risk of mistakes – resulting in service termination.

The Joint Petitioners opined that they have demonstrated a good payment history with BellSouth, according to BellSouth witness Morillo. The Joint Petitioners, therefore, recommended that the Commission find that BellSouth's proposed language is unnecessary to ensure that its invoices are paid. The Joint Petitioners maintained that BellSouth's proposal involves guesswork as to whether disputes will be properly and timely recognized, and as to when BellSouth will recognize receipt of payment. The Joint Petitioners argued that the opportunity for error and possible gamesmanship created by BellSouth's proposal is unreasonable, unacceptable, and contrary to the public interest. The Joint Petitioners maintained that their proposed language, which requires that BellSouth tell a Joint Petitioner exactly what it owes in dollars and cents, is a more equitable and sensible way to deal with late payments.

The Joint Petitioners recommended that the Commission adopt their proposed language for Section 1.7.2 of the Agreement.

BellSouth witness Morillo stated in supplemental direct testimony that BellSouth's position on this issue is that if a CLP receives a notice of suspension or termination from

BellSouth as a result of the CLP's failure to pay timely, the CLP should be required to pay all amounts that are past due as of the date of the pending suspension or termination action. Witness Morillo asserted that by definition the collections process is triggered when a customer does not pay its bills according to the terms of the agreement. He noted that once in collections, the risk associated with the customer is higher, based on the customer's own behavior. Witness Morillo noted that under the Joint Petitioners' proposed language, BellSouth would be limited to collecting the amount that was stated in the past due letter regardless of the customer's payment performance for subsequent bill cycles. He argued that BellSouth has the right and responsibility to protect itself from the higher risk associated with nonpayment by insuring that customers are not allowed to continue to stretch the terms of the contract and increase the likelihood of bad debt.

Addressing the Joint Petitioners' statement that the past due amount should be expressly indicated on the notice, witness Morillo stated that he would clarify the collections process for past due amounts. Witness Morillo noted that for Integrated Billing System (IBS) billed services (non-designed, i.e., UNE-P, etc.), if a customer becomes past due and BellSouth sends a treatment letter (i.e., suspension letter) requiring the customer to pay a certain past due amount or lose access to BellSouth ordering systems, BellSouth will require that the customer pay that certain amount and any additional amounts for which the customer has received additional treatment letters, or lose access to ordering systems. He stated that BellSouth would not withhold access to ordering systems for amounts where a collections notice had not been made to the customer. Witness Morillo noted that if, however, the customer does not comply and access to ordering systems is denied, payment of all additional amounts that have become past due will be required in order to restore access to the ordering systems. He maintained that the process for disconnection of service would work in a similar manner; BellSouth would not disconnect a customer if payment were made for all amounts for which a notice has been sent.

Witness Morillo maintained that Carrier Access Billing System (CABS) billed services (i.e., designed services) are collected differently. He stated that because the system does not have the capability to issue notices mechanically, the treatment process is more manual. Witness Morillo asserted that if a notice is sent to a customer for past due balances, and during that treatment process, additional payments become past due, BellSouth will require the customer to pay the amount on the notice, plus any additional amounts that have become past due in order to avoid suspension or termination of services.

Witness Morillo stated on cross-examination that the proposed provision allows BellSouth to suspend access and terminate service. He noted that the Joint Petitioners know when their BellSouth bills are due and that if they pay their bills on time this provision will never be invoked. Witness Morillo also noted that BellSouth has never suspended the Joint Petitioners for nonpayment.

Witness Morillo stated that it is probably correct under BellSouth's proposed language that there are circumstances where the Joint Petitioners would need to pay amounts in addition to those specified on the notice in order to avoid termination or suspension. He also agreed that potentially the Joint Petitioners may have to calculate an amount different from that specified on the termination notice in order to avoid termination. But, he asserted, the Joint Petitioners know if they did not pay a bill on time within 30 days and that there is no information that the Joint Petitioners would be missing.

Witness Morillo stated that the exact due date of payment will appear on the suspension or termination notice. He also agreed that in the case of two billing cycles, a Joint Petitioner may get fewer than 15 days to cure the past due amount. He also agreed that potentially with a third or fourth billing cycle within the notice timeframe the Joint Petitioners could have one day to pay the amounts. Witness Morillo also agreed that BellSouth could send out two flavors of a notice: one to pay all past due amounts and one to pay all amounts due.

Witness Morillo was asked about what counts as paying. He agreed that the concept of getting credit for paying the minute a CLP writes the check is analogous to the bill date on a BellSouth bill. Witness Morillo noted that he did not handle the posting of payments so he was not intimate with the process.

Witness Morillo explained that a treatment letter is a suspension letter.

On cross-examination by the Public Staff, witness Morillo agreed that he can make a distinction that the concept of a threat relates more to capability than to intent.

On re-direct, witness Morillo agreed that BellSouth's proposed language applies to only undisputed amounts owed. He also agreed that there was nothing that prevents the CLPs from invoking the billing dispute resolution provision of the Agreement.

BellSouth stated in its Brief that two important, agreed-upon contractual provisions should not be forgotten when deciding Matrix Item No. 100. First, Matrix Item No. 100 is limited to a Joint Petitioners' failure to pay undisputed amounts that are past due. Second, BellSouth noted, it will not commence any suspension or disconnection activity involving amounts that are subject to a billing dispute. BellSouth argued that given these circumstances, if a Joint Petitioner receives a notice of suspension or termination from BellSouth as a result of the Joint Petitioner's failure to timely pay amounts that are not subject to a billing dispute, the Joint Petitioner should be required to pay all undisputed amounts that are past due as of the date of the pending suspension or termination action. BellSouth asserted that the Joint Petitioners know when they receive bills, they know when the bills are due, and they admit that the amount of such bills can be predicted with a reasonable degree of accuracy. BellSouth further stated that nothing precludes the Joint Petitioners from contacting BellSouth with any questions they may have regarding amounts owed, and BellSouth stated that it will cooperate to promptly answer any billing related questions.

BellSouth maintained that the Joint Petitioners' apparent objection to BellSouth's proposed language for Matrix Item No. 100 is a concern about guessing what additional past due amounts must be paid to avoid suspension or termination. BellSouth noted that on March 21, 2005, BellSouth eliminated the Joint Petitioners' concern by revising its proposed language to remove the paranoia about perceived guesswork. BellSouth stated that, specifically, it is willing to agree that, upon request, BellSouth will advise of the additional undisputed amounts that have become past due since the issuance of the original notice of suspension or termination. BellSouth asserted that the Joint Petitioners have failed to respond to BellSouth's revised language on this Matrix Item.

BellSouth recommended that the Commission allow BellSouth to protect its financial interest by allowing BellSouth to discontinue providing service to any Joint Petitioner that fails to timely pay for services rendered and therefore, should adopt BellSouth's proposed language on Matrix Item No. 100. BellSouth asserted that ruling otherwise would be to allow the Joint Petitioners to have a revolving extension for payment of undisputed, past due amounts.

The Public Staff stated, in its Proposed Order, that it agrees with the Joint Petitioners that they should pay only the amount past due, expressly and plainly indicated on the notice as of the date of the notice. The Public Staff stated that it also believes that BellSouth's proposal would likely result in miscalculation of past due amounts, thereby potentially causing customer terminations. The Public Staff stated that it questions how BellSouth could require CLPs to pay an amount differing from the amount on the past due notice. The Public Staff maintained that it is unreasonable for the CLPs to be required to research, calculate, and pay any charges that become past due after a notice of suspension or termination for nonpayment has been sent. The Public Staff noted that a CLP would be forced to make assumptions and calculations that should normally be done by BellSouth. Therefore, the Public Staff asserted that it believes that the Joint Petitioners should not be required to calculate and pay past due amounts in addition to those specified by BellSouth's notice of suspension or termination for nonpayment in order to avoid suspension or termination.

The Commission notes that the language in dispute for Matrix Item No. 100 concerns whether a notice of suspension or termination for nonpayment should include the exact dollar amount due to BellSouth in order to avoid the suspension or termination or whether, upon request, BellSouth will provide information to the Joint Petitioners of the Additional Amounts Owed not reflected on the notice of suspension or termination. The Commission believes that any of the possible sanctions for nonpayment including the refusal of additional applications for service, the incompletion of pending orders for service, and/or suspension of access to ordering systems are business-impacting and could potentially result in customer termination. The Commission agrees with the Joint Petitioners that customer service termination is an extremely serious matter. The Commission further agrees with and understands BellSouth's argument that any service disruptions or terminations under this provision would only occur when a Joint Petitioner has not paid undisputed amounts that are past due.

However, the Commission believes the potential sanctions for nonpayment are too severe to let the risk of calculation errors potentially occur. Further, the Commission does not believe that BellSouth's new proposed language allowing the Joint Petitioners to request additional information from BellSouth is sufficient when the potential for customer termination is still present.

Therefore, the Commission finds it appropriate to adopt the Joint Petitioners' proposed language for Section 1.7.2 of Attachment 7 of the Agreement. This language will require BellSouth to specify in dollars and cents the amounts due to BellSouth to avoid any of the sanctions which could include customer termination.

CONCLUSIONS

The Commission concludes that it is appropriate to adopt the Joint Petitioners' proposed language concerning suspension or termination notices for Section 1.7.2 of Attachment 7 of the Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

ISSUE NO. 19 - MATRIX ITEM NO. 101: How many months of billing should be used to determine the maximum amount of the deposit?

POSITIONS OF PARTIES

JOINT PETITIONERS: The maximum amount of a deposit should not exceed two month's estimated billing for new CLPs or one and one-half month's actual billing for existing CLPs (based on average monthly billings for the most recent six month period). Alternatively, the maximum amount of deposit should not exceed one month's billing for services billed in advance and two months' billing for services billed in arrears.

BELLSOUTH: The average of two (2) months of actual billing for existing customers or estimated billing for new customers, which is consistent with the telecommunications industry's standard and BellSouth's practice with its end users.

PUBLIC STAFF: The Public Staff recommended that the Commission conclude that the deposit requirements specified in Commission Rule R12-4 are applicable and the language proposed by BellSouth should be incorporated into the Agreement.

DISCUSSION

The Joint Petitioners argued that being required to post excessive deposits places them at a competitive disadvantage. Deposits by their nature tie up capital, thus constrain Petitioners' ability to increase facilities deployment. The Joint Petitioners also argued that they have demonstrated a good payment history with BellSouth over the last several years, thus considerably decreasing BellSouth's risk, which they believe warrant a less onerous deposit policy.

BellSouth, through its witness Morillo, testified that service deposits are necessary to mitigate BellSouth's financial risk in the event a CLP does not or is unable to pay its bill. BellSouth has several criteria by which CLP deposit amounts are set, which includes payment history, liquidity, and bond rating. *See* Attachment 7, Section 1.8.5. BellSouth stated that these criteria are not in dispute.

The Public Staff pointed out that, in Docket No. P-500, Sub 18, the Commission addressed a similar issue and concluded that creditworthiness should be determined according to the principle set forth in Commission Rule R12-2(a)(2) for the establishment of credit for retail customers.[1] Commission Rule R12-4 is related to the principle set forth in Rule R12-2(a)(5). It limits the amount of the cash deposit to two-twelfths of the estimated charge for the service for the ensuing twelve-month period. The Public Staff believed that BellSouth's proposal to use the average of two month's of actual billing for existing customers or estimated billing for new customers is consistent with Commission Rule R12-4 and industry standards unlike the Joint Petitioners' proposal.

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[1] *In the Matter of Petition for Arbitration of ITC^DeltaCom Communications, Inc. with BellSouth Telecommunications, Inc. Pursuant to the Telecommunications Act of 1996,* Recommended Arbitration Order, Pgs. 78-79 (March 3, 2004).

Having reviewed the record and the language proposed by the Parties, the Commission believes that the deposit requirements specified in Commission Rule R12-4 are applicable for these circumstances and the language proposed by BellSouth should be incorporated into the Agreement.

CONCLUSIONS

The Commission concludes that the deposit requirements specified in Commission Rule R12-4 are applicable for these circumstances. Therefore, the language proposed by BellSouth should be incorporated into the Agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

ISSUE NO. 20 - MATRIX ITEM NO. 102: Should the amount of the deposit BellSouth requires from a CLP be reduced by past due amounts owed by BellSouth to the CLP?

POSITIONS OF PARTIES

JOINT PETITIONERS: Yes. The amount of security due from an existing CLP should be reduced by amounts due CLP by BellSouth aged over thirty (30) calendar days. BellSouth may request additional security in an amount equal to such reduction once BellSouth demonstrates a good payment history, as defined in the deposit provisions of Attachment 7 of the Agreement.

BELLSOUTH: No. The CLPs' remedy for addressing late payments by BellSouth should be suspension/termination of service or application of interest/late payment charges similar to BellSouth's remedy for addressing late payments by CLPs.

PUBLIC STAFF: The Public Staff recommended that the Commission conclude that the Joint Petitioners should not be allowed to offset security deposits by amounts owed to them by another carrier, but may exercise other options to address late payments, such as the assessment of interest or late payment charges, suspension of service, or disconnection after notice.

DISCUSSION

The Joint Petitioners argued that the provision for a deposit offset is appropriate since the deposit provisions of the Agreement are not reciprocal and BellSouth's payment history with the CLPs is often poor. The Joint Petitioners proposed that their language is appropriate because any credit risk exposure that BellSouth seeks to protect itself from is offset by amounts that BellSouth does not pay in a timely fashion.

BellSouth contended that the CLPs' remedy for addressing non-disputed late payments by BellSouth should be the suspension/termination of service or assessment of interest/late payment charges similar to BellSouth's remedy for addressing late payments by CLPs. BellSouth disagreed with the Joint Petitioners' characterization of BellSouth's payment history, stating that it has paid or disputed 91% of the invoices received from Xspedius Communications and Xspedius Corporation within 30 days of receipt. Further, BellSouth stated that, since December 2003, it has paid or disputed 97% of the invoices received from NuVox within 30 days of receipt.

The Public Staff noted that, in Docket No. P-500, Sub 18, the Commission found that terms in an agreement regarding the amount of deposits as well as the collection of deposits must be consistent with Commission Rule R12-4, which states that deposit amount shall not exceed two-twelfths of the estimated service for the ensuing 12-month period. The amount of the deposit is based upon usage without consideration of other external circumstances such as poor payment history. The Public Staff further noted that Commission Rule R12-5, Refund of Deposit, permits a deposit offset only when service is terminated. Specifically, the rule allows the holder of the deposit to withhold the amounts of any unpaid bills before refunding the deposit and accrued interest. The Public Staff stated that the Joint Petitioners suggest that the deposit offset should be applied routinely and that any outstanding balances owed to them be charged against their deposit requirements to BellSouth.

Commission Rule R12-4 does not authorize offsetting outstanding balances to the deposit requirement to another carrier. Therefore, the language proposed by the Joint Petitioners is rejected. The Commission agrees with BellSouth that CLPs should utilize existing remedies including assessment of late charges and discontinuation or suspension of services after proper notice for non-payment.

CONCLUSIONS

The Commission concludes that CLPs should not be allowed to offset security deposits by amounts owed to them by another carrier. CLPs may exercise other options to address late payments including the assessment of interest or late payment charges, suspension of service, or disconnection after notice.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

ISSUE NO. 21 - MATRIX ITEM NO. 103: Should BellSouth be entitled to terminate service to a CLP pursuant to the process for termination due to non-payment if the CLP refuses to remit any deposit required by BellSouth within 30 calendar days?

POSITIONS OF PARTIES

JOINT PETITIONERS: No. BellSouth should have a right to terminate services to a CLP for failure to remit a deposit requested by BellSouth only in cases where: (a) the CLP agrees that such a deposit is required by the Agreement, or (b) the Commission has ordered payment of such deposit. A dispute over a requested deposit should be addressed via the Agreement's Dispute Resolution provisions and not through "self-help".

BELLSOUTH: Yes. Thirty (30) calendar days is a commercially reasonable time period within which the CLP should have met its fiscal responsibilities.

PUBLIC STAFF: The Public Staff supported BellSouth's position.

DISCUSSION

The Joint Petitioners proposed the following language for Section 1.8.6 of the Agreement:

> 1.8.6 In the event [CLP] fails to remit to BellSouth any deposit requested pursuant to this Section and either agreed to by [CLP] or as ordered by the Commission within thirty (30) calendar days of such agreement or order, service to [CLP] may be terminated in accordance with the terms of Section 1.7 and subtending sections of this Attachment, and any security deposits will be applied to [CLP]'s account(s).

The Joint Petitioners contended that this language would prevent BellSouth from disconnecting service to a CLP if the parties disagreed on the amount of deposit required. Rather, BellSouth would be required to invoke the Agreement's Dispute Resolution process.

BellSouth proposed the following alternative language:

> 1.8.6 Subject to Section 1.8.7 following, in the event [CLP] fails to remit to BellSouth any deposit requested pursuant to this Section within thirty (30) calendar days of [CLP]'s receipt of such request, service to [CLP] may be terminated in accordance with the terms of Section 1.7 and subtending sections of this Attachment, and any security deposits will be applied to [CLP]'s account(s).

BellSouth's language gives a CLP 30 days to dispute a deposit requested by BellSouth. If the dispute is in writing, BellSouth must provide a written response explaining the basis for the deposit amount. Furthermore, a CLP would be required to place the deposit in escrow if the dispute took longer than 60 days to resolve. BellSouth argued that it has incurred losses in the past when a CLP failed to pay its bills, necessitating deposits to mitigate the risk of such losses.

The Public Staff stated in its Proposed Order that BellSouth must be allowed to bill reasonable deposits in accordance with Rule R12-4 in a timely manner for the provision of its services to customers, without the consent of either the billed party or the Commission. The Public Staff noted that the language proposed by the Joint Petitioners would place BellSouth in the position of potentially having to seek advance approval from both a CLP and the Commission every time it requested a deposit from the CLP. The Public Staff believed that such an arrangement would place an untenable burden on BellSouth and expose it to significant, unpredictable losses.

The Commission believes that there are already sufficient protections in place, in the Agreement and in Chapter 12 of the Commission's Rules and Regulations to discourage BellSouth from abusing its authority to require customer deposits. Attachment 7, Section 2 of the Agreement ("Billing Disputes") contains provisions accepted by all parties that allow for billed deposits to be disputed within 30 days of billing. Section 2.1.6 gives the parties 60 days following the dispute notification date to resolve the dispute and sets forth the specific obligations of each party during this period. In the event they are unable to resolve the dispute amicably, either party may then petition the Commission for resolution, pursuant to Section 13 of the General Terms and Conditions ("Resolution of Disputes").

CONCLUSIONS

Accordingly, the Commission concludes that the language proposed by BellSouth with respect to termination of service due to non-payment of a deposit for Section 1.8.6 is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

ISSUE NO. 22 - MATRIX ITEM NO. 104: What recourse should be available to either Party when the Parties are unable to agree on the need for or amount of a reasonable deposit?

POSITIONS OF PARTIES

JOINT PETITIONERS: If the Parties are unable to agree on the need for or amount of a reasonable deposit, either Party should be able to file a petition for resolution of the dispute and both Parties should cooperatively seek expedited resolution of such dispute.

BELLSOUTH: If a CLP does not agree with the amount or need for a deposit requested by BellSouth, the CLP may file a petition with the Commission for resolution of the dispute and BellSouth would cooperatively seek expedited resolution of such dispute. BellSouth shall not terminate service during the pendency of such a proceeding provided that the CLP posts a payment bond for the amount of the requested deposit during the pendency of the proceeding.

PUBLIC STAFF: The Public Staff agreed with the Joint Petitioners' position.

DISCUSSION

The Parties proposed the following language regarding the reasonableness of deposits requested by BellSouth and the procedures to be followed during a complaint proceeding to challenge deposit requirements.

Joint Petitioners:

1.8.7 The Parties will work together to determine the need for or amount of a reasonable deposit. If the Parties are unable to agree, either party may file a petition for resolution of the dispute and both parties shall cooperatively seek expedited resolution of such dispute.

BellSouth:

1.8.7 The Parties will work together to determine the need for or amount of a reasonable deposit. If [CLP] does not agree with the amount or need for a deposit requested by BellSouth, [CLP] may file a petition with the Commission for resolution of the dispute and both Parties shall cooperatively seek expedited resolution of such dispute. BellSouth shall not terminate service during the pendency of such a proceeding provided that [CLP] posts a payment bond for the amount of the requested deposit during the pendency of the proceeding.

The Joint Petitioners maintained that BellSouth's proposal to require CLPs to post a payment bond for the pendency of the complaint proceeding would effectively put them in the position of losing a deposit dispute before the issues were properly adjudicated. BellSouth stated that during the past two years, there have been instances where a CLP filed for bankruptcy while a dispute relating to a deposit request was pending. Therefore, BellSouth argued that the bond posting requirement is necessary to minimize its financial risk.

BellSouth's testimony citing instances in which it unsuccessfully sought state assistance to resolve deposit disputes is insufficient to persuade the Commission that CLPs should be required to post bonds as a precondition to challenging BellSouth's deposit requirements in a Commission complaint proceeding. The Joint Petitioners' proposed wording, in combination with the provisions approved elsewhere in this order for "Billing Disputes" (Section 2 of Attachment 7) and "Resolution of Disputes" (Section 13 of the General Terms and Conditions), should be sufficient to protect the Parties from unnecessary financial risk during the pendency of complaints before the Commission.

CONCLUSIONS

The Commission concludes that the language proposed by the Joint Petitioners on the need for or amount of a deposit to be included in Section 1.8.7 of the Agreement is appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That the Joint Petitioners and BellSouth shall prepare and file a Composite Agreement in conformity with the conclusions of this Order as outlined in the Commission's November 3, 2000 Order Modifying Composite Agreement Filing Requirements issued in Docket No. P-100, Sub 133. Such Composite Agreement shall be in the form specified in paragraph 4 of Appendix A in the Commission's August 19, 1996 Order in Docket Nos. P-140 Sub 50, and P-100, Sub 133, concerning arbitration procedure (Arbitration Procedure Order) as amended by the November 3, 2000 Order.

2. That, not later than Thursday, August 25, 2005, a party to the arbitration may file objections to this Order consistent with paragraph 3 of the *Arbitration Procedure Order.*

3. That, not later than Thursday, August 25, 2005, any interested person not a party to this proceeding may file comments concerning this Order consistent with paragraphs 5 and 6, as applicable, of the *Arbitration Procedure Order.*

4. That, with respect to objections or comments filed pursuant to decretal paragraphs 2 or 3 above, the party or interested person shall provide with its objections or comments an executive summary of no greater than one and one-half pages, single-spaced, or three pages, double-spaced containing a clear and concise statement of all material objections or comments. The Commission will not consider the objections or comments of a party or person who has not submitted such executive summary or whose executive summary is not in substantial compliance with the requirements above.

5. That parties or interested persons submitting Composite Agreements, objections or comments shall also file those Composite Agreements, objections or comments, including the

executive summary required in decretal paragraph 4 above, on an MS-DOS formatted 3.5-inch computer diskette containing noncompressed files created or saved in Word format.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of July, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp072505.01

Appendix A
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Glossary of Acronyms
Docket Nos. P-772, Sub 8;
P-913, Sub 5; P-989, Sub 3;
P-824, Sub 6; and P-1202, Sub 4

Act	Telecommunications Act of 1996
Agreement	Interconnection Agreement
AICPA	American Institute of Certified Public Accountants
BellSouth	BellSouth Telecommunications, Inc.
BOCs	Bell Operating Companies
CABS	Carrier Access Billing System
CLEC	Competitive Local Exchange Company
CLP	Competing Local Provider
CMDS	Centralized Message Distribution System
Commission	North Carolina Utilities Commission
CPNI	Customer Proprietary Network Information
CSR	Customer Service Record
DSL	Digital Subscriber Line
EEL	Enhanced Extended Link (Loop)
ESP	Enhanced Service Provider
FCC	Federal Communications Commission
FTTC	Fiber-to-the-curb
FTTH	Fiber-to-the-home
IBS	Integrated Billing System
ICA	Interconnection Agreement
ICO	Independent Telephone Company
ILEC	Incumbent Local Exchange Company (Carrier)
ISP	Internet Service Provider
ITC or ITC^DeltaCom	ITC^DeltaCom Communications, Inc.
IXC	Interexchange Carrier

Appendix A
Page 2 of 2

Joint Petitioners	NewSouth, NuVox, KMC, and Xspedius
KMC	KMC Telecom V, Inc. and KMC Telecom III, LLC
LOA	Letter of Authorization
LSR	Local Service Request
MDUs	Multiple Dwelling Units
MPOE	Minimum Point of Entry
NewSouth	NewSouth Communications Corp.
NuVox	NuVox Communications, Inc.
OSS	Operations Support Systems
Public Staff	Public Staff – North Carolina Utilities Commission
RAO	Recommended Arbitration Order
RNM	Routine Network Modification
SEEM	Self-Effectuating Enforcement Mechanism
SGAT	Statement of Generally Available Terms and Conditions
SOC	Supplemental Order Clarification
SQM	Service Quality Measurement
TA96	Telecommunications Act of 1996
TDM	Time Domain Multiplexing
TELRIC	Total Element Long-Run Incremental Cost
TIC	Tandem Intermediary Charge
TRO	Triennial Review Order
TRRO	Triennial Review Remand Order
UNE	Unbundled Network Element
UNE-P	Unbundled Network Element – Platform
Verizon	Verizon Virginia, Inc.
WorldCom	WorldCom, Inc.
xDSL	Digital Subscriber Line
Xspedius	Xspedius Communications, LLC on behalf of its operating subsidiary, Xspedius Management Co. Switched Services, LLC

DOCKET NO. W-274, SUB 478

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina, for Authority to Increase Rates for Water Service in all its Service Areas in North Carolina	))))	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD IN: Community Room, Gastonia Police Department, 200 E. Long Avenue, Gastonia, North Carolina on Monday, November 1, 2004, at 7:00 p.m.

Auditorium, Charles A. Cannon Memorial Library, 27 Union Street, Concord, North Carolina on Tuesday, November 2, 2004, at 7:00 p.m.

Courtroom B, District Court Building, 111 Main Avenue NE, Hickory, North Carolina on Monday, November 8, 2004, at 7:00 p.m.

Council Chambers, Mt. Airy City Hall, 300 S. Main Street, Mt. Airy, North Carolina on Tuesday, November 9, 2004, at 7:00 p.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, November 30, 2004, at 7:00 p.m.

Industrial Commission Conference Room 6227, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, January 11, 2005, at 9:30 a.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, February 9, 2005, at 9:30 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; Commissioner J. Richard Conder and Commissioner James Y. Kerr, II

APPEARANCES:

For Heater Utilities, Inc.:

William E. Grantmyre, President and House Counsel, Post Office Drawer 4889, Cary, North Carolina 27519

For the Using and Consuming Public:

Kendrick C. Fentress and Elizabeth D. Szafran, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On July 28, 2004, Heater Utilities, Inc. (Heater or Company) filed an application with the Commission for authority to increase its rates for water utility service in all of its service areas in North Carolina.

On August 18, 2004, the Commission issued an Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, and Requiring Customer Notice. On August 24, 2004, the Commission issued an Order Revising Hearing Location. On September 15, 2004, the Company filed a Certificate of Service reflecting that it had given notice as required.

Public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this case:

November 1 – Gastonia	Nelson Belk, Vicky Bryant, Mark Rhom, Sarah Jordan, Matt Fravor, Paul King, Jill Solesbee, Jeffrey Black, Clarence Rhom
November 2 – Concord	Gene Choquette, Tom Sides
November 8 – Hickory	No witnesses
November 9 – Mt. Airy	Berle Ayers, Jessica Hill
November 30 – Raleigh	Walter Ezzell, John Czinege, Lyle Hart, Edward Szymanski, Larry Outlaw, Greg Mobley, Holly Jones, Don Wilson, Rita Fellers, Deborah Staves, Addie Laws, Debbie Nichols, Floyd Earhart, Tony Correale, Ruben Centeno
January 11 – Raleigh	No witnesses

No party filed an intervention petition in the form required by Commission Rules R1-5 and R1-19.

On November 22, 2004, the Company filed the direct testimony of William E. Grantmyre and Freda Hilburn.

In response to a Public Staff motion, on December 13, 2004, the Commission issued an Order Continuing Hearing and Revising Procedural Schedule in which the Commission established new deadlines for the submission of the Public Staff's direct testimony and Heater's rebuttal testimony, prescribed a deadline for the filing of intervention petitions, ordered that the hearing set for January 11, 2005, be conducted for the sole purpose of receiving public witness testimony, provided that an evidentiary hearing for the purpose of receiving testimony from Heater, the Public Staff, and other formal parties to this proceeding would be held on February 9, 2005, and noted that interested members of the public that were unable to attend any of the prior hearings would be allowed to present public witness testimony at the February 9, 2005, hearing.

On January 5, 2005, Heater and the Public Staff filed a joint stipulation reflecting an agreement between the parties as to the appropriate capital structure and cost of capital, and the maximum allowable level of expert witness expense related to capital structure and cost of capital (Joint Stipulation).

On January 25, 2005, the Public Staff filed the testimony of Kenneth E. Rudder, Utilities Engineer, Water Division, and the testimony and exhibit of Katherine A. Fernald, Supervisor, Water Section, Accounting Division. On February 2, 2005, Heater filed the rebuttal testimony of Mr. Grantmyre, the rebuttal testimony and exhibit of Richard D. Hugus, and a Report on Service Related Customer Testimony by Richard J. Durham. On February 8, 2005, the Public Staff filed the revised testimony of Mr. Rudder and the revised testimony and exhibit of Ms. Fernald, and Heater filed corrections to the rebuttal testimony and exhibit of Mr. Hugus.

On February 9, 2005, the evidentiary hearing was held as scheduled. Heater presented the direct testimony of Mr. Grantmyre, as well as the direct testimony and exhibit of Ms. Hilburn. Mr. Grantmyre adopted Ms. Hilburn's testimony as Heater no longer employs her. The Public Staff presented the direct testimony of its witnesses Mr. Rudder and Ms. Fernald. Heater presented the rebuttal testimony of Mr. Grantmyre, and the rebuttal testimony and exhibit of Mr. Hugus. Jerry Tweed testified on rebuttal, adopting the Report on Service Related Customer Testimony prepared by Mr. Durham.

On March 1, 2005, Heater filed updated financial schedules (Heater's Updated Schedules) to identify the schedules filed by Ms. Fernald on February 8, 2005, with which Heater disagrees.

On March 3, 2005, Heater filed a motion to include in the record the corrected rebuttal testimony and exhibit of Mr. Hugus, which Heater filed on February 8, 2005, but did not admit into evidence at the hearing on February 9, 2005. On March 9, 2005, the Commission issued an order accepting the corrected rebuttal testimony (Hugus Corrected Rebuttal) into the record for purposes of this proceeding.

Various consumer statements of position were filed in this docket before the evidentiary hearing.

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. Heater 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. Heater 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 operations.

3. The test period appropriate for use in this proceeding is the twelve months ended March 31, 2004, updated to August 31, 2004.

4. Heater's present water rates and the water rates requested in its application are:

WATER AND SEWER – RATES

WATER RATES:

Base charge (zero consumption)

Meter Size	Existing Rates	Proposed Rates
<1" meter	$ 12.11	$ 14.78
1" meter	30.29	36.94
1-1/2" meter	60.57	73.88
2" meter	96.91	118.20
3" meter	181.71	221.63
4" meter	302.86	369.39
6" meter	605.71	738.77
Usage charge - per 1,000 gallons	3.51	4.28
Usage charge - per 100 cubic feet	2.63	3.20
Metered Rates: (Riverview Estates, Valley Woods MHP, and Cross Creek MHP)		
Base charge, zero usage	12.10	14.78
Usage charge, per 1,000 gallons	2.95	4.28
Metered Rates: (Wilson Farms and Weatherstone Subdivisions)		
Base charge, zero usage	9.55	14.78
Usage charge, per 1,000 gallons	2.99	4.28
Metered Rates: (Cotesworth Downs and Carolina Oaks Subdivisions)		
Base charge, zero usage	18.00	14.78
Usage charge, per 1,000 gallons	3.87	4.28
Metered Rates: (Huntdell Subdivision)		
Base charge, zero usage	9.50	14.78
Usage charge, per 1,000 gallons	2.80	4.28
Metered Rates: (Goodwill Acres Subdivision)		
Base charge, zero usage	8.25	14.78
Usage charge, per 1,000 gallons	2.73	4.28
Flat Rates:		
Residential rate	33.86	41.31
Commercial @ motel rate	152.36	N/A
Commercial @ business rate	50.79	61.97
Commercial @ residential rate	33.86	41.31
Reconnection Charges:		
If water service cut off by utility for good cause	35.00	50.00
If water service discontinued at customer's request	5.00	35.00
New customer account fee	20.00	35.00

5. At the end of the updated test year ending August 31, 2004, Heater provided water utility service to approximately 34,781 (34,091 metered and 690 flat rate) water customers in all its service areas in North Carolina.

6. Heater is providing adequate water service. Heater filed a report with the Commission on February 2, 2005, addressing the issues in each subdivision from which complaints were received at the public hearings.

Rate Base

7. The appropriate level of plant in service, net of contributions in aid of construction (CIAC), for use in this proceeding is $49,277,545.

8. It is appropriate to remove from plant in service payments to developers related to future customers.

9. The appropriate amount of accumulated deferred income taxes to deduct from rate base in this proceeding is $192,046.

10. The appropriate level of accumulated depreciation for use in this proceeding is $15,727,235.

11. The appropriate level of developer and other payables to be deducted from rate base is $98,495.

12. It is not appropriate to include the accounts payable to the North Carolina Department of Transportation (DOT) of $125,000 in the total amount of developer and other payables to be deducted from rate base in this case.

13. The appropriate level of working capital allowance for use in this proceeding is $1,208,042.

14. The appropriate level of rate base used and useful in providing water utility service is $39,962,130, consisting of utility plant in service, net of CIAC, of $49,277,545, acquisition adjustments of $5,839,380, meters and supplies inventory of $773,528, and working capital allowance of $1,208,042, reduced by customer deposits of $204,431, unclaimed refunds of $42,826, developer and other payables of $98,495, accumulated deferred income taxes of $192,046, accumulated depreciation of $15,727,235, and accumulated amortization of acquisition adjustments of $871,332.

Revenues

15. The appropriate level of end-of-period water service revenues under existing rates is $14,109,078.

16. The appropriate level of late payment fees for use in this proceeding is $19,753.

17. The appropriate level of miscellaneous revenues to include in this proceeding is $579,107.

18. The appropriate level of uncollectibles to deduct from revenues in this proceeding is $39,561.

19. The total level of revenues under present rates is $14,668,377.

Customer Growth

20. The appropriate level of customer growth for use in this proceeding is 3.29%.

Operation & Maintenance (O&M) Expenses

21. The appropriate level of salaries and wages to include in O&M expenses is $2,139,121.

22. The salaries for two open O&M positions should be included in this case.

23. The appropriate level of employee benefits for O&M employees for use in this proceeding is $452,097.

24. The appropriate level of O&M expenses is $5,690,907.

General Expenses

25. The appropriate level of salaries and wages to include in general expenses is $843,904.

26. The salary for one open general and administrative (G&A) position should be included in this case.

27. The appropriate level of employee benefits for G&A employees for use in this proceeding is $136,932.

28. The appropriate level of contractual services for use in this proceeding is $251,257.

29. The total Sarbanes-Oxley costs for Aqua America, Inc. (Aqua), Heater's parent company, since June 1, 2004, to be allocated to Heater in this case, is $1,257,897.

30. Heater's ratepayers should not bear any Sarbanes-Oxley costs incurred by Aqua prior to its acquisition of Heater's stock on June 1, 2004.

31. It is appropriate to spread the nonrecurring portion of the Sarbanes-Oxley costs over a three-year period.

32. It is appropriate to allocate the adjusted level of Sarbanes-Oxley costs to Heater using the Public Staff's recommended customer equivalent / nonregulated allocation factor of 6.33%.

33. Based on the foregoing, the appropriate level of external Sarbanes-Oxley costs to include in contractual services is $46,542.

34. It is not appropriate to include any additional internal corporate or Sarbanes-Oxley costs in contractual services.

35. The appropriate level of insurance for use in this proceeding is $215,950.

36. The appropriate level of workers compensation, general liability, and automobile insurance claims to include in this case is the average claims incurred by Heater for the past four years.

37. The appropriate levels of workers compensation and general liability premiums to include in this proceeding should be based on the level of salaries and wages approved herein.

38. It is appropriate to reduce expenses in this case by $300,000 to offset the adverse impact to Heater's ratepayers of the recent transfer of Heater's stock to Aqua.

39. The appropriate level of general expenses is $2,096,971.

Depreciation and Taxes

40. The appropriate level of depreciation and amortization expense for use in this proceeding is $2,443,930.

41. The appropriate level of other taxes to include in this proceeding is $429,186.

42. Based on the other findings and conclusions set forth in this Order, the appropriate level of regulatory fees for use in this proceeding is $17,602.

43. Antenna lease revenues are appropriately included in revenues in this proceeding and, as jurisdictional revenues, should be subject to regulatory fees.

44. Based on other findings and conclusions set forth in this Order, the appropriate level of gross receipts taxes for use in this proceeding is $575,288.

45. Based on the other findings and conclusions set forth in this Order, the appropriate level of state income tax for use in this proceeding is $145,254.

46. Based on the other findings and conclusions set forth in this Order, the appropriate level of federal income tax for use in this proceeding is $685,956.

Overall Cost of Capital

47. The appropriate capital structure to employ for purposes of this proceeding consists of 50% debt and 50% equity. The embedded cost of debt associated with this capital structure is 6.55%.

48. The cost of common equity capital for Heater for purposes of this proceeding is 10.7%.

49. The overall fair rate of return that the Company should be allowed the opportunity to earn on its rate base is 8.63%.

Rates, Fees and Other Matters

50. The Commission finds that Heater's water rates should be changed to amounts that, after pro forma adjustments, will produce an increase in total annual revenue of $1,489,192. This increase will allow Heater the opportunity to earn an 8.63% overall return on its rate base for water operations, which the Commission has found to be reasonable upon consideration of the findings in this Order.

51. The reconnection charges and new customer account fees will remain unchanged.

52. It is appropriate to increase Heater's returned check charge to $25.

53. Heater should reduce the transactions with any affiliated companies to writing and file these contracts with the Commission as required by G.S. 62-153 within 90 days of the effective date of this Order.

54. Heater should begin accounting for construction work in progress (CWIP) in compliance with the Uniform System of Accounts.

55. Heater should begin recording the mark-up received from developers as CIAC.

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 - 5

The evidence supporting these findings of fact is contained in the application and in the testimony of Public Staff witness Rudder and is not contested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony of public witnesses, Public Staff witness Rudder, Heater witness Tweed, and the Report on Service Related Customer Testimony filed by Heater on February 2, 2005.

Six customer hearings were held across the state and customers testified objecting to the rate increase and/or describing service/quality complaints as follows:

Hearing Location	Number of Customers Testifying
Gastonia	9
Concord	2
Hickory	0
Mt. Airy	2
Raleigh	15
Raleigh	0

A total of 28 customers from 19 service areas testified in opposition to the proposed rate increase and, of that total, 23 customers from 16 service areas testified regarding service related issues. In Gastonia, Mr. Belk and Ms. Solesbee questioned the efficiency of Heater's meter reading practices and Ms. Bryant, testifying on behalf of her elderly mother, stated that her mother would be better served by a metered system than by the flat rate system Heater currently provided in her mother's subdivision. In Mt. Airy, Mr. Ayers also questioned Heater's meter reading efficiency. Most of the other water service issues involved complaints of low pressure, discolored water, malodorous water, or bad tasting water. In particular, five customers testified at the Raleigh hearing regarding the water quality at Wildcat Creek Subdivision in Orange County (Wildcat Creek).

The Public Staff received numerous customer complaint letters regarding the proposed rate increase. Most of the letters objected to the rate increase itself. Some of the letters also indicated water quality and water pressure problems that were consistent with the water quality and pressure problems noted by customers who testified at the public hearings.

In response to the consumer complaints, Heater filed a 27-page report describing the systems serving the 16 service areas from which service-related complaints originated and the reasons for many of the problems testified to by the customers. In addition, the report details numerous operational and/or capital improvements that have been made to the systems. Regarding questions about meter reading, the report indicated that Heater has been converting its flat rate systems to metered systems and specifically will proceed with installation of meters in the Morningside Park Subdivision in Gastonia, where Ms. Bryant's mother lives. The report and Heater witness Tweed also stated that Heater has a very cost efficient method for reading meters by using vehicles for curb side reading and hand-held computers for data entry.

Mr. Tweed also testified regarding the problems at Wildcat Creek with elevated radiological contaminants and other water quality problems. According to Mr. Tweed, Heater installed a treatment system to remove radium particles in Well #4 serving Wildcat Creek in early December. After installation, a recent test of a water sample revealed no detectable level of radium 226 and 228 in the treated water. Moreover, Mr. Tweed confirmed that Heater has made the necessary capital improvements to resolve the water quality problems at Wildcat Creek testified to at the public hearing. For example, the boil water notice mentioned by several customers has been lifted as the result of the installation of new well facilities.

Public Staff witness Rudder testified that several systems were unapproved by the Division of Environmental Health (DEH) of the Department of Environment and Natural Resources and that Heater is in the process of contracting with an engineer to prepare plans and specifications for DEH approval.

Mr. Rudder also testified that he was satisfied with Heater's progress to date in dealing with the problems at Wildcat Creek, with the caveat that Heater needs to continue to try to resolve the radioactivity problem. He recommended that Heater continue to respond to and resolve these complaints in a timely and effective manner.

In Mr. Rudder's opinion, Heater is providing adequate water utility service to its customers. He testified that Heater has made much progress in correcting problems in its western area and is continuing to address water quality problems as they are encountered.

The Commission is concerned about quality of service issues noted by customers in the complaint letters and testified to by customers at the public hearings, particularly those customers from Wildcat Creek, and discussed in Heater's 27-page report filed on February 2, 2005. The Commission will take appropriate action to ensure that Heater continues to address service quality issues in the subdivisions discussed in its report, as well as throughout all of its service areas. Heater should be required to file two reports updating the Commission on the status of the service quality in Wildcat Creek. These reports should address any operational problems experienced, complaints received, and service improvements made or proposed to be made. Heater should file the first of such reports by August 31, 2005, and as well as a final report by February 28, 2006. The Public Staff is requested to monitor this situation and file a response with the Commission within 30 days after the filing of each report.

The Commission agrees with Public Staff witness Rudder concerning several systems that remain unapproved by DEH. It is the Commission's understanding that Heater has contracted with the proper sources to assist in rectifying this matter. The Commission still feels that it is necessary to keep abreast of the process that is being made to resolve this issue. Therefore, Heater is required to file by August 31, 2005, a report to the Commission indicating systems that are still unapproved, the reasons the systems are unapproved, and a schedule showing the steps that will be taken to meet approval. The Public Staff is requested to review such report and file a response within 30 days after the filing of the unapproved systems report.

Based on the foregoing, the Commission concludes Heater is providing adequate service, is making sufficient efforts to improve service in areas with problems, and should continue its efforts to do so. The Commission concludes that Heater should be required to provide follow-up reports for quality of service at Wildcat Creek and systems that are unapproved by DEH. These reports are to be filed on the dates specified by the Commission in the above discussion.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 - 14

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witnesses Hugus and Grantmyre. The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of rate base for water operations to be used in this proceeding:

Item	Company	Public Staff	Difference
Plant in service, net of CIAC	$49,658,370	$49,277,545	$ (380,825)
Acquisition adjustments	5,839,380	5,839,380	0
Customer deposits	(204,431)	(204,431)	0
Unclaimed refunds	(42,826)	(42,826)	0
Developer and other payables	(98,495)	(223,495)	(125,000)
Accumulated deferred income taxes	(194,036)	(192,046)	1,990
Accumulated depreciation	(15,756,203)	(15,727,235)	28,968
Accum. amort. of acquisition adj.	(871,332)	(871,332)	0
Meters and supplies inventory	773,528	773,528	0
Working capital allowance	1,270,440	1,199,922	(70,518)
Original cost rate base	$40,374,395	$39,829,010	$ (545,385)

As shown in the preceding table, the Public Staff and the Company agree on the levels of acquisition adjustments, customer deposits, unclaimed refunds, accumulated amortization of acquisition adjustments, and meters and supplies inventory. Therefore, the Commission finds and concludes that the levels agreed to by the parties for these items are appropriate for use in this proceeding.

PLANT IN SERVICE, NET OF CIAC

The only difference between Heater and the Public Staff regarding plant in service, net of CIAC, concerns the Public Staff's adjustment to remove the portion of the purchase price paid for systems that is related to future customers. Public Staff witness Fernald testified that the purchase price paid for new service areas is based on the number of lots to be served times a set price per lot. When Heater acquires a new service area, it records the entire purchase price paid to the developer to plant in service. Ms. Fernald determined the amount of plant related to future customers by comparing the purchase price booked with the price of the plant that would be considered used and useful, based on the number of customers served as of August 31, 2004.

Company witness Hugus testified that Heater's procedure for buying systems, which it has used since at least 1986, is fair and reasonable and does not burden existing customers with the costs of future development. Mr. Hugus further testified that even though an area may not be completely built out, the water system is being used to deliver water, and was therefore prudently built. Finally, Mr. Hugus testified that the current revenue from the existing customers in the areas in question is supporting not only the marginal operating costs of production, but is also in excess of the return needed to support the investment for the lots not yet occupied.

Whether a plant cost is related to current or future customers is a fact to be determined based on the evidence in the case.[1] The utility bears the burden of showing whether a plant is used and useful.[2] In the systems at issue in this case, which are detailed on Schedule 2-1(b) of Ms. Fernald's Exhibit I, the purchase price paid by Heater was clearly per lot, and varied based on the number of lots for the system. As a result, the purchase price included by Heater in this case is related to not only current customers, but also future customers. For example, in the Stanley Acres system, Heater paid $400 per lot, and since there were 56 lots in the system, Heater paid $22,400 for the system, and has included this total purchase price in rate base in this case. However, as of August 31, 2004, Heater was serving only one customer in Stanley Acres.

Current customers should not have to pay for plant costs related to future customers. According to the decisions of the Supreme Court of North Carolina in *State ex rel. Utilities Commission v. Carolina Water Service, Inc., of North Carolina*, 328 N.C. 299, 401 S.E. 2nd 353 (1991), and *State ex rel. Utilities Commission* v. *Public Staff-North Carolina Utilities Commission*, 333 N.C. 195, 424 S.W. 2nd 133 (1993), levels of investment needed to serve future customers should only be included in rate base when accompanied by a showing of the additional expenses and revenues associated with that additional plant investment. The record does not contain sufficient evidence of such future costs and expenses. Therefore, the Commission concludes that the purchase price paid by Heater for lots not yet served should be removed from plant in service, as recommended by the Public Staff. The fact that the water systems in the subdivisions at issue are being used to serve current customers is not determinative, since the question is not whether the system is in use at all, but rather, what portion of Heater's cost in the system, if any, is related to future customers. In most situations where the Commission has addressed used and useful plant, the plant item itself is being used to provide service. For example, in cases where the Commission has addressed excess capacity in elevated storage tanks, such as the rate case proceeding for Carolina Water Service, Inc. of NC in Docket No. W-354, Sub 128, the fact that the tank was connected to the system and was being used did not prevent the Commission from making an excess capacity adjustment to recognize that a portion of the tank was excess capacity related to future customers. As a result, the fact that the record does not contain sufficient evidence of the extent to which existing plant is used to serve existing and future customers or to apply the matching principle properly, the Commission concludes that the Public Staff's proposed adjustment is appropriate.

Finally, Heater can negotiate its contracts so that the per lot purchase price is paid as customers connect, rather than up front at closing. Although Company witness Hugus contended that Heater's procedures for purchasing systems had not changed in years, this contention appears to be incorrect. For example, in Docket No. W-274, Sub 501, the purchase price for the system involved was $400 per lot, but was payable quarterly as lots request service, rather than in total at closing. In this manner, current customers of the system are not burdened with plant costs for future customers.

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[1] *See State ex rel. Utils. Comm'n. v. Carolina Utility Customers Ass'n.*, 314 N.C. 171, 181, 333 S.E.2d 259, 266 (1985) (whether property is used and useful is a question of fact to be determined by the Commission upon the evidence).

[2] *Id.*

DEVELOPER AND OTHER PAYABLES

The parties disagree on the appropriate treatment of an account payable to DOT for a main relocation. In her prefiled testimony, Public Staff witness Fernald included $155,700 related to the accounts payable to DOT in the amount of developer and other liabilities to be deducted from rate base. Ms. Fernald testified that "[o]ne of Heater's mains had to be relocated due to DOT's Outer Loop project in Wake County, and the relocation was paid for by DOT, to be reimbursed by Heater." Since Heater had not reimbursed DOT for the main relocation, Ms. Fernald included the accounts payable in developer and other payables. Ms. Fernald testified that this adjustment was necessary since Heater is only entitled to recover its own investment.

Company witness Grantmyre testified that Heater owns and operates the Bayleaf Master System in northern Wake County. In constructing the new I-540 Outer Loop, DOT advised Heater it would be necessary for Heater to relocate certain Heater water mains. These water mains were installed within highway rights of way pursuant to highway encroachment agreements executed by Heater and DOT and, under these highway encroachment agreements, Heater, like all other water utilities, must pay for the water main relocations.

Mr. Grantmyre testified that Heater entered into an agreement with DOT for DOT's contractor to perform the water main relocation work. Once the work was completed, DOT would invoice Heater and Heater would make the payment. The water main relocation was completed by DOT's contractor in 2002 and Heater booked as an account payable $155,710 in December 2002.

According to Mr. Grantmyre, despite several requests by Heater to DOT for an invoice so that Heater could pay the payable to DOT, DOT has not yet provided Heater an invoice nor has DOT requested payment from Heater. In January 2005, DOT advised Heater that DOT expects the invoice to be approximately $125,000 rather than the $155,710 previously booked by Heater as an account payable.

The Commission concludes that it is not appropriate to reduce rate base by the $125,000 at issue here. The facts as to the $125,000 Heater investment are uncontroverted. The relocated water mains have been in service since 2002 providing service to Heater's customers and are used and useful. Heater was required by DOT to relocate these water mains and the only issue is whether Heater should be denied rate base treatment of this $125,000 investment because of DOT's delay in invoicing Heater. Heater has not in anyway caused the delay in the invoicing. The payment of the $125,000 is a legal obligation of Heater. The Public Staff did not contest either that this payable was a legal obligation or the amount of the payable.

ACCUMULATED DEFERRED INCOME TAXES

The difference between Heater and the Public Staff regarding accumulated deferred income taxes results from the parties' disagreement over the level of plant in service. Based on the conclusions concerning plant in service reached elsewhere in this Order, the Commission concludes that rate base should be reduced by $192,046 of accumulated deferred income taxes.

ACCUMULATED DEPRECIATION

The difference between Heater and the Public Staff regarding accumulated depreciation results from the parties' disagreement over the level of plant in service. Based on the conclusions concerning plant in service reached elsewhere in this Order, the Commission concludes that $15,727,235, the amount of accumulated depreciation presented by the Public Staff, is reasonable and appropriate for use in this proceeding.

WORKING CAPITAL ALLOWANCE

The Company and the Public Staff have recommended different amounts for a working capital allowance as a result of having recommended different levels of expenses and certain taxes. Based upon conclusions regarding the appropriate levels of expenses and taxes reached elsewhere in this Order, the Commission concludes that the appropriate level of working capital allowance for use in this proceeding is $1,208,042.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of original cost rate base for water operations for use in this proceeding is $39,962,130, consisting of the following:

Item	Amount
Plant in service, net of CIAC	$49,277,545
Acquisition adjustments	5,839,380
Customer deposits	(204,431)
Unclaimed refunds	(42,826)
Developer and other payables	(98,495)
Accumulated deferred income taxes	(192,046)
Accumulated depreciation	(15,727,235)
Accum. amort. of acquisition adj.	(871,332)
Meters and supplies inventory	773,528
Working capital allowance	1,208,042
Original cost rate base	$39,962,130

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 - 19

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Fernald and Rudder and Company witnesses Grantmyre and Hugus. The Company did not contest the levels of service revenues, late payment fees, miscellaneous revenues, and uncollectibles recommended by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Fernald and Rudder and Company witnesses Grantmyre and Hugus. The Company did not contest the customer growth factor recommended by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21 - 24

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witnesses Grantmyre and Hugus. 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
Salaries and wages - O&M	$2,139,121	$2,095,791	$ (43,330)
Employee benefits - O&M	452,097	445,808	(6,289)
Purchased water	266,648	266,648	0
Purchased power	824,422	824,422	0
Chemicals	281,991	281,991	0
Maintenance and repair	132,639	132,639	0
Testing fees	638,723	638,723	0
Transportation	489,253	489,254	1
Permit fees	75,925	75,925	0
Signal lines	13,666	13,666	0
Tank painting	33,312	33,312	0
Bad weather amortization	16,010	16,010	0
Freight and other miscellaneous	327,099	327,099	0
Total operation and maintenance exp.	$5,690,906	$5,641,288	$ (49,618)

As shown on the preceding table, the Public Staff and the Company agree on the levels of purchased water, purchased power, chemicals, maintenance and repair, testing fees, permit fees, signal lines, tank painting, bad weather amortization, and freight and other miscellaneous. Also, although there is a rounding difference of one dollar between the levels of transportation expense presented by the parties, the Company agreed with the level of transportation expense recommended by the Public Staff. Based on the foregoing, 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 - O&M

The parties disagree on whether the salaries associated with two open O&M positions should be included in salaries and wages expense in this case. Public Staff witness Fernald testified that these positions should be removed since the actual amount of salary for any future employees, and when the employees will be hired, is unknown. Ms. Fernald further testified that a company the size of Heater will always have some turnover, and reflecting salaries for all positions, including open positions, in allowable expenses for ratemaking purposes will overstate the ongoing level of salaries.

Company witness Grantmyre disagreed with the Public Staff's adjustment. Mr. Grantmyre testified that the duties assigned to the open positions are being performed by either hourly rate personnel, whose overtime would be at 150% of their hourly rate, or by outside contracting services. Mr. Grantmyre also testified that that the open positions were necessary for Heater to provide safe, adequate, and reliable service and that, historically, Heater has experienced a very low vacancy rate. Finally, Mr. Grantmyre testified that if the positions were excluded, then an adjustment should be made to include the cost of additional contract services and overtime paid to Heater's other employees.

The Commission concludes that the salaries related to the two open O&M positions should be included in this case. Heater is in the process of filling these positions and there was no evidence that these positions were not needed. Accordingly, the appropriate level of salaries and wages to include in operation and maintenance expenses is $2,139,121.

EMPLOYEE BENEFITS - O&M

The difference in the levels of employee benefits - O&M recommended by the parties results from the parties' disagreement over the appropriate level of salaries and wages to include in this proceeding. Having previously determined the appropriate level of salaries and wages - O&M, the Commission concludes that the appropriate level of employee benefits - O&M is $452,097.

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 $5,690,907, which consists of the following:

Item	Amount
Salaries and wages - O&M	$2,139,121
Employee benefits - O&M	452,097
Purchased water	266,648
Purchased power	824,422
Chemicals	281,991
Maintenance and repair	132,639
Testing fees	638,723
Transportation	489,254
Permit fees	75,925
Signal lines	13,666
Tank painting	33,312
Bad weather amortization	16,010
Freight and other miscellaneous	327,099
Total operation and maintenance expense	$5,690,907

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25 - 39

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witnesses Grantmyre and Hugus. The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of general expenses to be used in this proceeding:

Item	Company	Public Staff	Difference
Salaries and wages - G&A	$ 843,904	$ 832,471	$ (11,433)
Employee benefits - G&A	136,932	133,623	(3,309)
Purchased power - office	17,984	17,984	0
Materials and supplies - office	87,498	87,498	0
Contractual services	399,132	251,257	(147,875)
Rent	76,434	76,434	0
Transportation	10,584	10,584	0
Insurance	268,837	215,950	(52,887)

Regulatory commission expense	76,547	76,547	0
Telephone, postage, and other misc.	415,208	415,208	0
Interest on customer deposits	12,322	12,322	0
Adjustment for impact of stock transfer	0	(300,000)	(300,000)
Annualization adjustment	198,588	198,588	0
Inflation adjustment	53,763	53,763	0
Total general expenses	$2,597,733	$2,082,229	$ (515,504)

As shown on the preceding table, the Public Staff and the Company agree on the levels of purchased power - office, materials and supplies - office, rent, transportation, regulatory commission expense, telephone, postage, and other miscellaneous, interest on customer deposits, annualization adjustment, and inflation adjustment. 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 - G&A

The parties disagree on whether the salary for an open G&A position should be included in salaries and wages expense in this case. Public Staff witness Fernald testified that this position should be removed since the actual amount of salary for any future employee, and when the employee will be hired, is unknown. Ms. Fernald further testified that a company the size of Heater will always have some turnover and that reflecting salaries for all positions, including open positions, will overstate the ongoing level of salaries.

Company witness Grantmyre disagreed with the Public Staff's adjustment to remove the open G&A position. Mr. Grantmyre testified that the duties for the open position are being performed by either salaried G&A personnel or by outside contracting services. Mr. Grantmyre also testified that that the open position is necessary for Heater to provide safe, adequate, and reliable service, and that historically, Heater has experienced very low vacancies of employee positions. Finally, Mr. Grantmyre testified that if the position was excluded, then an adjustment should be made to include the cost of additional contract services and overtime paid to Heater's other employees.

Heater is in the process of filling this position and there was no evidence that this position was not needed. The Commission concludes that the salary related to the open G&A position at issue should be included in this case. Accordingly, the Commission concludes that the appropriate level of salaries and wages to include in general expenses is $843,904.

EMPLOYEE BENEFITS - G&A

The difference in the levels of employee benefits - G&A recommended by the parties results from the parties' disagreement over the appropriate level of salaries and wages to include in this proceeding. Having previously determined the appropriate level of salaries and wages - G&A, the Commission concludes that the appropriate level of employee benefits - G&A is $136,932.

CONTRACTUAL SERVICES

The parties disagree on the level of costs allocated to Heater from Aqua, Heater's parent company, to be included in contractual services in this case. It is necessary to closely examine charges and allocation of costs from affiliated companies since these transactions are at less than arm's length and affiliated relationships provide an opportunity and incentive for companies to maximize the profits of the combined affiliated companies.[1] Accordingly, public utilities are required under G.S. 62-153 to file with the Commission copies of contracts with affiliated companies. However, Heater has not filed contracts covering any affiliated transactions, including the allocation of accounting and other corporate costs.

That the Company has not filed the contract as required does not prevent this Commission from considering costs assigned to Heater from Aqua in this case, as long as the Commission determines that the charges are just and reasonable. The utility bears the burden of making this showing to the Commission.[2] It is a well-established principle that rates should be based only on the costs necessary to provide utility service. Thus, whenever there are common costs allocated from a parent or service company, the Commission must make sure that the total costs being allocated are reasonable and appropriately allocated, so that costs related to other operations, Heater's nonregulated operations, and other jurisdictions are excluded from Heater's cost of service.

In this case, the difference between the parties in the costs allocated from Heater to Aqua relates to the following items:

Item	Amount
External Sarbanes-Oxley costs	$ 18,785
Internal Sarbanes-Oxley costs	46,762
Other internal corporate costs	82,328
Total	$ 147,875

External Sarbanes-Oxley Costs

Public Staff witness Fernald calculated the amount of external Sarbanes-Oxley costs for Heater's consolidated operations based on the costs incurred by Aqua since it acquired Heater on June 1, 2004, allocated to Heater using the customer / nonregulated factor of 6.33%. Ms. Fernald testified that she did not include any costs incurred by Aqua prior to the acquisition of Heater since these costs should have been allocated among the companies owned by Aqua in the month they were incurred. Ms. Fernald testified that she then spread the portion of the costs that were nonrecurring over a three-year period, as proposed by Heater. Finally, Ms. Fernald allocated her annual level of external Sarbanes-Oxley costs to Heater's water operations based on the number of customers, resulting in an annual level of external Sarbanes-Oxley costs to be included in this case of $46,542. Ms. Fernald also testified that in response to a data request, the

[1] *See State ex rel. Utils. Comm'n. v. Morgan*, 7 N.C. App. 576, 588-589, 173 S.E.2d 479, 487-488 (1970) (Commission to examine closely transactions between utilities and affiliated companies to protect ratepayers from excessive rates), *rev'd on other grounds*, 277 N.C. 255, 177 S.E.2d 405 (1970), *adhered to on reh'g*, 278 N.C. 235, 179 S.E.2d 419 (1971).

[2] *Id.* at 588, 173 S.E.2d at 487.

Company indicated that the $230,040 of Sarbanes-Oxley costs included on its application was incorrect, and provided an updated amount of $111,825.

Company witness Hugus testified that Aqua's total external costs for Sarbanes-Oxley was $1,560,837, of which 6.55% or $102,234 should be allocated to Heater. Mr. Hugus further testified that 63.9% of these costs should be allocated to Heater's water operations.

First, the parties disagree on the total external costs to be allocated to Heater in this case. According to the Public Staff, the total Sarbanes-Oxley costs incurred by Aqua is $1,686,799. The Public Staff then removed $428,902 of costs that were incurred prior to the acquisition of Heater's stock by Aqua, resulting in Sarbanes-Oxley costs incurred by Aqua after June 1, 2004 of $1,257,897. In its rebuttal testimony, the Company listed total Sarbanes-Oxley costs of $1,560,837. However, the Company did not explain why its amount differed from the Public Staff, nor did the Company provide any rebuttal testimony disputing the Public Staff's adjustment to remove costs incurred prior to June 1, 2004. The Commission agrees with the Public Staff that costs incurred by Aqua prior to its acquisition of Heater should not be allocated to Heater. Therefore, the total amount of Sarbanes-Oxley costs for Aqua since June 1, 2004, to be allocated to Heater in this case, is $1,257,897.

The next area of disagreement is how to handle the nonrecurring portion of these costs. Public Staff witness Fernald indicated that $1,097,000 of these costs were recurring costs based on information provided by the Company, resulting in $160,897 of nonrecurring costs. Ms. Fernald spread these nonrecurring costs over a three-year period, as proposed by the Company. In its direct testimony, the Company testified that it "amortized over a three year period the external audit fees associated with the initial review of the internal controls over financial reporting." The Company did not address the Public Staff's treatment of the nonrecurring costs in its rebuttal testimony. Costs that do not occur every year should not be included as an annual expense. Therefore, the Commission concludes that it is appropriate to spread $160,897, the nonrecurring portion of the Sarbanes-Oxley costs, over a three-year period.

The final difference in the levels of external Sarbanes-Oxley costs recommended by the parties concerns the appropriate allocation factor to use to allocate these costs from Aqua to Heater's consolidated operations. Public Staff witness Fernald allocated the costs to Heater using her customer / nonregulated factor of 6.33%. Ms. Fernald testified that Aqua allocated common costs, such as accounting costs, to Heater based on the number of customers, and, according to information provided by the Company, Heater represents 6.53% of Aqua's regulated operations based on the number of customers. Ms. Fernald further testified that Aqua does not recognize its nonregulated operations, such as contract operations, in its allocation of common costs. Based on an allocation percentage for nonregulated operations of 3%, Ms. Fernald calculated a customer / nonregulated factor to be used in allocating common costs to Heater of 6.33% (97% times 6.53%).

Company witness Hugus used a factor of 6.55% to allocate his level of total Sarbanes Oxley costs to Heater's consolidated operations. Mr. Hugus did not explain the difference between his allocation factor and the Public Staff's factor, nor did he provide any testimony disputing the Public Staff's adjustment to recognize Aqua's nonregulated operations in the calculation of the allocation factor.

The Commission concludes that the allocation factor recommended by the Public Staff of 6.33%, which recognizes Aqua's nonregulated operations, is the appropriate factor to use in allocating Sarbanes-Oxley costs to Heater's consolidated operations. As previously discussed, costs related to other operations, such as nonregulated operations, should be excluded from a utility's cost of service.

Based on the foregoing, the appropriate level of external Sarbanes-Oxley costs to include in contractual services is $46,542.

Internal Sarbanes-Oxley Costs

Public Staff witness Fernald testified that she did not include any amount for the time spent by Aqua employees on Sarbanes-Oxley since the Company had not provided documentation supporting the costs. In his rebuttal testimony, Company witness Hugus testified that the internal Sarbanes-Oxley costs for Aqua, allocated to Heater, was $73,180, of which 63.9% should be allocated to Heater's water operations. Mr. Hugus testified at the hearing that the Company had provided documentation to the Public Staff in support of the $73,180 in the form of time sheets, billings that had been exchanged between Aqua and Heater, a chart that illustrated these particular things, and further documentation concerning two names of Aqua employees.

The Commission concludes that the Company has not met its burden of proof that the charges at issue are just and reasonable. As previously discussed, the charges from Aqua to Heater are affiliated transactions, and as such, should be closely scrutinized for reasonableness. In this case, the Company has failed to file contracts covering the affiliated transactions at issue, as required by G.S. 62-153. Without these contracts, details of the transactions involved and how the costs are allocated to Heater are not available. Public Staff witness Fernald testified that the Company had failed to provide adequate documentation supporting these charges. Although Company witness Hugus contended at the hearing that the Company had provided what it considered to be adequate documentation, the Company did not file or provide any of this documentation to the Commission so that the Commission could review the reasonableness of the charges.

Based on review of the record in this case, the Commission cannot find that the charges proposed by the Company are reasonable. First, without reviewing supporting documentation, the Commission does not know whether the total costs to be allocated are reasonable, actual costs, and not estimated costs. The Commission notes that in the allocation of insurance claims, as discussed below, the Company allocated an estimated costs, not actual costs. Second, the Commission does not know whether the method of allocating or assigning the costs among the Aqua companies is reasonable, and whether the costs have properly been allocated to nonregulated operations. The Commission notes that Public Staff witness Fernald testified that Aqua does not recognize its nonregulated operations in its allocation of common costs. Third, the Commission does not know whether the calculation of the total costs and allocation of the costs to Heater is accurate, or whether it contains errors similar to those made by the Company in its application in which it included $230,040 of Sarbanes-Oxley costs when the amount should have been $111,825, or the errors made in its rebuttal testimony. Finally, the Commission cannot determine what portion of the internal Sarbanes-Oxley costs is nonrecurring versus recurring costs.

Other Internal Corporate Costs

In his prefiled rebuttal testimony, Company witness Hugus stated that there were additional charges from Aqua of $237,619. Mr. Hugus further testified that 63.9% of these costs should be allocated to Heater's water operations, resulting in $151,838 of costs for Heater's water operations. At the hearing, Mr. Hugus testified, "there was a question about names having been doubled up in various parts. We investigated it and found that was, in fact, true, the amount of approximately $73,000. We reduced the $237,619 that you see in the lower right-hand chart [filed with Mr. Hugus' corrected rebuttal testimony on February 8, 2005] by $73,000 and then multiplied the ensuing amount by 63.9 percent, which is the portion of customers covered by the rate application to the whole of Heater Utilities." This correction resulted in a corrected amount of internal corporate costs of $105,077, according to the Company. When asked on cross-examination when the Company had provided the $105,077 to the Public Staff requesting that it be included in this case, Mr. Hugus pointed to the one page exhibit attached to his rebuttal testimony, which was filed on February 2, 2005, and corrected on February 8, 2005.

Also during cross-examination, Company witness Hugus testified that the additional Human Resources costs from Aqua, which have already been included by the Public Staff in contractual services, were included in the additional corporate charges. In Heater's Updated Schedules filed on March 1, 2005, the Company indicated that Mr. Hugus' rebuttal testimony and exhibit should be corrected in order to eliminate the duplication of $35,500 of Aqua's Human Resources expenses. In the revised chart provided with Heater's Updated Schedules, the Company reduced the total additional corporate charges from $164,439 to $128,839. However, the Company made two errors in its calculation. First, the Company removed $35,000, instead of $35,500. Second, the Company had a mathematical error in its chart, since $164,439 reduced by $35,000 is $129,439, not $128,839. Correction of these two errors results in a Company amount of additional corporate costs for Heater's consolidated operations of $128,939, of which 63.9% would be allocated to Heater's water operations, resulting in $82,392 of additional corporate costs at issue in this case.

Although Public Staff witness Fernald indicated in her testimony that she had not included the internal Sarbanes-Oxley costs previously discussed since the Company had not provided adequate documentation, she did not indicate that there were any other corporate charges that the Company had requested which she had not included. Based on Mr. Hugus' testimony on cross-examination, it appears that during the Public Staff's investigation the Company had not provided these additional costs to the Public Staff with a request that they be included in this case. In fact, in a response to Public Staff data requests concerning corporate charges, the Company had indicated that the corporate charges included in this case were based on work performed by four persons at Aqua, instead of an allocation of various departments at Aqua. These specific allocations are shown on the confidential Public Staff Grantmyre Cross Examination Exhibit No. 3. The $144,000 for these four persons was included in Contractual Services - Other by the Company[1] and the Public Staff included these costs in its recommended level of contractual services.

The Commission concludes that the Company has not met its burden of proof that the affiliated corporate charges at issue are just and reasonable. Although Company witness Hugus

[1] The $144,000 was included in Item 10, Workpaper 81 of the Company's Form W-1, which was filed with its application on July 28, 2004.

requested that these costs be included in this case in his rebuttal testimony, he did not provide any documentation supporting the reasonableness of the costs.

Based on review of the record in this case, the Commission cannot find that the charges proposed by the Company are reasonable. In particular, without reviewing supporting documentation, the Commission cannot determine whether the costs are accurate, or include errors or costs that have already been included elsewhere in this case. As previously discussed, the Company has already had to make two revisions to the amount of additional corporate charges to eliminate costs that had already been included elsewhere in this case, and the final amount filed by the Company in its updated schedules still contains mathematical errors. Also, as with the internal Sarbanes-Oxley costs previously discussed, without supporting documentation, the Commission cannot determine whether the costs are reasonable, actual costs or estimated costs, whether the allocation of costs is reasonable, and whether costs have properly been allocated to nonregulated operations.

Summary

Based on the foregoing, the Commission concludes that the appropriate level of contractual services for use in this proceeding is $251,257.

INSURANCE

The difference in the level of insurance recommended by the parties relates to the following items:

Item	Amount
Level of insurance claims	$ 52,282
Calculation of premiums based on payroll	605
Total	$ 52,887

The first area of difference between the parties pertains to the amount of workers compensation, general liability, and automobile insurance claims to be included in this proceeding. Company witness Grantmyre testified that Aqua's allocation procedure, which is the actual insurance cost that Heater pays, is appropriate for use in this proceeding. Mr. Grantmyre testified that Aqua allocates to its companies, including Heater, the total projected losses, which are calculated based upon Aqua's seven year historical loss experience modified for increased exposures and industry trending factors. Mr. Grantmyre further testified that this allocation procedure is similar to commercial insurance policies purchased on the open market whereby Heater pays a predetermined annual premium and is protected against extremely large claims in one year.

Public Staff witness Fernald included the cost of claims based on the average claims incurred by Heater for the past four years. Ms. Fernald also noted that Heater had not filed contracts covering affiliated transactions with Aqua or other companies, including the allocation of insurance costs, as required by G.S. 62-153.

As previously discussed under contractual services, it is necessary to closely examine charges and allocation of costs from affiliated companies. The fact that the Company has not filed an affiliated contract covering the allocation of insurance costs does not prevent this

Commission from considering insurance costs assigned to Heater from Aqua in this case, as long as the Commission determines that the charges are just and reasonable.

The Company is proposing that costs be allocated, rather than directly assigned. The total cost for claims being allocated is a projected cost, and not the actual cost incurred. Furthermore, the projected cost allocated by the Company to Heater is based on Aqua's operations, prior to its acquisition of Heater, and does not reflect Heater's claims history. For that reason, the manner in which Aqua assigns costs to Heater is not directly analogous to an insurance premium, which is usually based on the insured's claim experience. The Public Staff is proposing that the claims costs be directly assigned, and therefore, has included the average claims for Heater in its recommended level of insurance costs.

As a general rule, the common corporate costs to be allocated should be the actual costs, and should not be estimated or marked up. Furthermore, it is preferable that costs be directly assigned whenever possible. If the costs cannot be directly assigned, allocation procedures are then appropriate. In this case, the claims costs at issue can be directly assigned. Therefore, the Commission concludes that the appropriate level of claims to be included in this case is the actual average claims for Heater for the last four years, as recommended by the Public Staff, instead of allocating an estimated claims amount as proposed by the Company.

The Commission disagrees with Heater's contention that Aqua's allocation procedure should be used in this case, since it is the actual cost that Heater will pay. The costs in this case are not predetermined premiums that Heater is paying to an outside insurance vendor. Instead, these costs are being assigned to Heater from an affiliated company. The fact that Heater pays Aqua the amount allocated to it by Aqua on its books does not prevent the Commission from reviewing the appropriateness of the Company's allocation methodology, and making an adjustment to the amount assigned to Heater in this rate case.

Under the Company's proposal, it is unclear what happens to any excess collections by Aqua. Company witness Grantmyre testified that Aqua does not true up the allocated amounts to reflect the actual claims incurred. If this is the case, the parent company benefits when the actual claims incurred are less than the projected losses allocated to its subsidiaries.

The remaining difference between the parties involves the level of workers compensation and general liability premiums to include in this case. The parties are recommending different levels for these premiums due to the 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 for operation and maintenance and general expenses, the Commission concludes that the appropriate corresponding levels of workers compensation and general liability premiums should be included in this proceeding.

Based on the foregoing, the Commission concludes that the appropriate level of insurance to include in this proceeding is $216,555.

IMPACT OF STOCK TRANSFER

Public Staff witness Fernald testified that Aqua has chosen to treat its recent acquisition of Heater's stock as an Internal Revenue Code Section 338(h) asset sale for tax purposes. While taking this election may benefit Aqua's stockholders, it adversely impacts Heater's ratepayers. Ms. Fernald testified that, as a result of this election, Heater's rate base has increased by approximately $2.5 million, resulting in an increase in the revenue requirement for this case by over $300,000. Ms. Fernald pointed out that, under the stipulation in the stock transfer proceeding (Docket No. W-274, Sub 465), the parties agreed that the benefits and costs of the stock transfer, including tax implications, would be at issue in future proceedings and that the Commission retained the right to take whatever action it deemed necessary to protect the interests of Heater's ratepayers in future proceedings. Finally, because the Section 338(h) election will have an adverse impact on Heater's ratepayers, Ms. Fernald recommended that expenses be reduced by $300,000 to protect the ratepayers from this adverse impact.

Company witness Hugus testified that there is no basis for the expense reduction recommended by the Public Staff. Specifically, Mr. Hugus testified that (1) the taxes deferred by Allete, Heater's former parent company, were paid, (2) the ratepayers are only entitled to the rate base reduction as long as it exists, (3) service to customers has not been adversely affected, (4) the customers have never contributed or benefited from the vast majority of the accumulated deferred income taxes balance, and (5) the link between the proposed adjustment and the pre-merger deferred tax balance is undeniable.

In the stock transfer proceeding, the Commission approved the stipulation between the Public Staff and Aqua. The stipulation, which was filed on May 17, 2004, states:

> h. The Public Staff and Aqua agree that this stipulation shall have no ratemaking implications, other than those discussed in paragraphs a-g. In addition, the Public Staff and Aqua agree that the benefits and costs to Heater of the stock transfer, including tax implications, may be at issue in future proceedings. The Public Staff and Aqua further agree that either party may assert any position on ratemaking or other regulatory issues with regard to these benefits and costs and that the Commission retains the right to take whatever action it deems necessary to protect the interests of Heater's customers in future proceedings.

Aqua has elected to treat the sale of Heater's stock as an Internal Revenue Code Section 338(h) asset sale for tax purposes. If Aqua had not taken this election, the reduction to rate base for accumulated deferred income taxes would be over $2.5 million more than the amount included in this case. Therefore, as a result of Aqua taking the Section 338(h) election, rate base in this case has increased by approximately $2.5 million, thereby increasing Heater's revenue requirement for this case by over $300,000. Based on the foregoing, the Commission concludes that the Section 338(h) election taken by Aqua has had a significant negative impact on Heater's ratepayers.

The Commission retained the right to take whatever action it deems necessary to protect the interests of Heater's ratepayers in future proceedings from negative impacts due to the stock transfer, such as the impact of the Section 338(h) election. The only question is whether there are cost savings due to the stock transfer that offset the $300,000 negative impact. Public Staff witness Fernald testified that while the adjustment for the adverse impact of the stock transfer should be offset by any savings due to the transfer, she did not believe that there is a significant amount of savings, net of cost increases, to offset the impact of the Section 338(h) election.

Ms. Fernald further testified that she was unable to determine the exact amount of savings and costs since she did not have available the actual amount of costs under Allete prior to the stock transfer.

In his prefiled rebuttal testimony, Company witness Hugus indicated that there were net savings of $68,038, which consisted of his calculated savings of $444,846 reduced by $376,808 of net costs. On February 8, 2005, the Company filed corrected rebuttal testimony in which Mr. Hugus testified that there were net savings of $245,721, which consisted of his calculated savings of $416,345, reduced by the additional costs of $170,624 that he recommended be included in this case, above the amounts already recommended by the Public Staff. On cross-examination, Mr. Hugus testified that he did not compare the costs under Aqua to those under Allete in evaluating whether there were any cost increases. Mr. Hugus also testified that he was not aware that Allete was a much larger company than Aqua and that under Allete there was a larger base over which to spread any common corporate costs, such as stockholder's expense. The Company also stipulated at the hearing that savings calculated by Mr. Hugus would need to be updated to reflect the revised amounts for this case.

In Heater's Updated Schedules filed on March 1, 2005, the Company indicated that Mr. Hugus' rebuttal testimony and exhibit should be corrected in order to reflect the Public Staff's revised testimony filed on February 8, 2005. This correction resulted in a revised savings of $239,593, which is the Company's calculated savings of $387,468 reduced by the additional costs of $147,875 that the Company recommends be included in the case, above the amounts already included by the Public Staff.

The Commission concludes that the Company has not shown that there are significant savings, net of cost increases, to offset the $300,000 negative impact to ratepayers due to the Section 338(h) election. First, not all of the decreases in costs listed by Mr. Hugus as savings are due to the stock transfer. For example, the decrease in employee benefits - O&M is related to all adjustments to O&M salaries of $122,062, not just the adjustment to incentive compensation for O&M of $67,110. Second, the savings calculated by the Company is based on the Public Staff's recommended amounts, and not the amounts proposed by the Company. For example, the $47,434 of open G&A positions includes $11,433 related to an open position that the Company proposes be included in this case, as discussed under salaries and wages.

Also, the Company's net costs of $147,875 do not include all increases in costs due to the transfer. In his calculation, Mr. Hugus only includes the additional costs that he is proposing be included in this case, above the amounts recommended by the Public Staff. Mr. Hugus did not include any increase in costs due to the stock transfer that are already reflected in the Public Staff's schedules. Some of the expenses recommended by the Public Staff already reflect significant cost increases. For example, based on the per books amounts listed in the Company's application, the Public Staff's recommended expense levels reflect an increase in contractual services of $137,528, from the per books amount of $113,729 to the Public Staff recommended level of $251,257. The Public Staff's recommended expense levels also reflect other increases in costs, such as stockholders expense. Mr. Hugus does not recognize these cost increases in his calculation of the net costs due to the transfer.

Finally, to determine the correct amount of net savings due to the transfer, one would need to review what the costs would have been under Allete, and compare those costs to the costs under Aqua. Mr. Hugus did not perform this analysis, and did not provide any information on increases in costs from the amounts under Allete. Allete is a much larger corporation than Heater with a much larger base over which to spread common corporate costs, and, therefore, common corporate costs allocated to Heater under Allete, such as accounting, Sarbanes-Oxley and stockholders expenses, would be lower than the costs allocated to Heater under Aqua.

The Commission does not agree with the Company's contention that the Commission cannot make an adjustment to offset the impact of the stock transfer, including the impact due to the Section 338(h) election, since ratepayers are only entitled to a rate base reduction for accumulated deferred income taxes as long as it exists. While the Commission agrees that accumulated deferred income taxes in this case should reflect the actual amounts for Heater based on the Section 338(h) election, this does not prevent the Commission from protecting Heater's ratepayers in this case from any negative impact of the stock transfer, as the Commission retained the right to do so in the transfer proceeding.

The Commission also does not agree with the Company's contention that the ratepayers have not paid for the majority of the accumulated deferred income taxes balance. Specific costs are not tracked in rates, but rather rates established by the Commission are deemed to be just and reasonable to cover the cost of providing service on an ongoing basis, including a return on rate base. If the rates are not adequate to cover operations, including increases or decreases in rate base, then it is the responsibility of a utility's management to file for a rate increase. Just as plant additions are being recovered from ratepayers, even though the utility has not had a rate case since the plant additions were made, ratepayers have also paid the amount of book depreciation over tax depreciation through rates (i.e., accumulated deferred income taxes).

Based on the foregoing, the Commission concludes that it is appropriate to reduce expenses in this case by $300,000 to offset the impact to Heater's ratepayers of the recent transfer of Heater's stock to Aqua.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of general expenses for use in this proceeding is $2,097,576, which consists of the following:

Item	Amount
Salaries and wages - G&A	$ 843,904
Employee benefits - G&A	136,932
Purchased power - office	17,984
Materials and supplies - office	87,498
Contractual services	251,257
Rent	76,434
Transportation	10,584
Insurance	216,555
Regulatory commission expense	76,547
Telephone, postage, and other misc.	415,208
Interest on customer deposits	12,322
Adjustment for impact of stock transfer	(300,000)
Annualization adjustment	198,588
Inflation adjustment	53,763
Total general expenses	$2,097,576

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 40 - 46

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Fernald and Company witnesses Grantmyre and Hugus. 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 and amortization exp.	$2,459,163	$2,443,930	$ (15,233)
Other taxes	429,186	424,994	(4,192)
Regulatory fees	17,602	17,602	0
Gross receipts tax	575,288	575,288	0
State income tax	108,760	150,327	41,567
Federal income tax	513,617	709,912	196,295
Total depreciation and taxes	$4,103,616	$4,322,053	$ 218,437

As shown in the preceding table, the Public Staff and the Company agree on the level of gross receipts tax. Therefore, the Commission finds and concludes that the level agreed to by the parties for this item is appropriate for use in this proceeding.

DEPRECIATION AND AMORTIZATION EXPENSE

The difference between Heater and the Public Staff regarding depreciation and amortization expense results from the parties' disagreement over the level of plant in service. Based on the conclusions concerning plant in service reached elsewhere in this Order, the Commission concludes that the amount of depreciation and amortization expense presented by the Public Staff is reasonable and appropriate for use in this proceeding.

OTHER 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 for operation and maintenance and general expenses, the Commission concludes that the appropriate level of other taxes for use in this proceeding is $429,186.

REGULATORY FEES

The only issue to be addressed related to regulatory fees concerns the treatment of revenues from antenna leases. Public Staff witness Fernald testified that Heater has not been reporting antenna lease revenues on its regulatory fee reports, but that the Company had indicated that it would not oppose reporting antenna lease revenues for regulatory fee purposes going forward if the Commission determines that the revenues are subject to regulatory fees. Ms. Fernald recommended that the Commission make a ruling addressing the issue of whether antenna lease revenues are subject to regulatory fees. The Company did not address this issue in its rebuttal testimony or at the hearing.

Whether or not antenna lease revenues are subject to regulatory fees affects the level of regulatory fees to be included in this case. Under G.S. 62-302(b)(2), the regulatory fee paid by a regulated utility to the Commission is based upon the public utility's North Carolina jurisdictional revenues. G.S. 62-302(b)(4) defines North Carolina jurisdictional revenues as "all revenues derived or realized from intrastate tariffs, rates, and charges approved or allowed by the Commission or collected pursuant to Commission order or rule, but not including tap-on fees or any other form of contributions in aid of construction." Since antenna lease revenues are appropriately included in revenues in this proceeding and, therefore, are jurisdictional revenues, the Commission concludes that antenna lease revenues are subject to regulatory fees. Based on the foregoing, the appropriate level of regulatory fees under present rates is $17,602.

STATE INCOME TAX

The Company and the Public Staff are recommending different levels of state income tax due to the different levels of revenues and expenses recommended by each party. 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 income tax for use in this proceeding is $145,254.

FEDERAL INCOME TAX

The Company and the Public Staff are recommending different levels of federal income tax due to the different levels of revenues and expenses recommended by each party. 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 federal income tax for use in this proceeding is $685,956.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47 - 49

The evidence supporting these findings of fact is contained in the Joint Stipulation. The Commission has reviewed the Joint Stipulation and it is hereby approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 50

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 the Company's gross revenue requirements, incorporate the findings and conclusions reached by the Commission in this Order.

SCHEDULE I
HEATER UTILITIES, INC.
DOCKET NO. W-274, SUB 478
STATEMENT OF OPERATING INCOME AVAILABLE FOR RETURN
WATER OPERATIONS
For the Twelve Months Ended March 31, 2004, Updated to August 31, 2004

Item	Present Rates	Increase Approved	After Approved Increase
Operating revenues:			
Service revenues	$14,109,078	$1,491,217	$15,600,295
Late payment fees	19,753	2,087	21,840
Miscellaneous revenues	579,107	70	579,177
Uncollectibles	(39,561)	(4,182)	(43,743)
Total operating revenues	14,668,377	1,489,192	16,157,569
Operating revenue deductions:			
O&M expenses	5,690,907	0	5,690,907
General expenses	2,097,576	0	2,097,576
Depreciation & amort. exp.	2,443,930	0	2,443,930
Other taxes	429,186	0	429,186
Regulatory fees	17,602	1,787	19,389
Gross receipts tax	575,288	59,567	634,855
State income tax	145,254	98,521	243,775
Federal income tax	685,956	465,261	1,151,217
Total oper. revenue deductions	12,085,699	625,136	12,710,835
Net operating income for return	$ 2,582,678	$ 864,056	$ 3,446,734

SCHEDULE II
HEATER UTILITIES, INC.
DOCKET NO. W-274, SUB 478
STATEMENT OF RATE BASE AND RATE OF RETURN
WATER OPERATIONS
For the Test Year Ended March 31, 2004, Updated to August 31, 2004

Item	Amount
Plant in service, net of CIAC	$ 49,277,545
Acquisition adjustments	5,839,380
Customer deposits	(204,431)
Unclaimed refunds	(42,826)
Developer and other payables	(98,495)
Accumulated deferred income taxes	(192,046)
Accumulated depreciation	(15,727,235)
Accum. amort. of acquisition adj.	(871,332)
Meters and supplies inventory	773,528
Working capital allowance	1,208,042
Original cost rate base	$ 39,962,130
Rates of Return:	
Present	6.46%
Approved	8.63%

SCHEDULE III
HEATER UTILITIES, INC.
DOCKET NO. W-274, SUB 478
STATEMENT OF CAPITALIZATION AND RELATED COSTS
WATER OPERATIONS
For the Twelve Months Ended March 31, 2004, Updated to August 31, 2004

Item	Ratio %	Original Cost Rate Base	Embedded Cost	Net Operating Income
Present Rates:				
Debt	50.00%	$19,981,065	6.55%	$1,308,760
Equity	50.00%	19,981,065	6.38%	1,273,918
Total	100.00%	$39,962,130		$2,582,678
Approved Rates:				
Debt	50.00%	$19,981,065	6.55%	$1,308,760
Equity	50.00%	19,981,065	10.70%	2,137,974
Total	100.00%	$39,962,130		$3,446,734

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 51 - 52

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Rudder and is not contested by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Fernald and Company witness Hugus. Ms. Fernald recommended that Heater reduce transactions with any affiliated companies to writing and file these contracts with the Commission as required by G.S. 62-153 within 90 days of the effective date of the order issued in this case. Mr. Hugus testified that the Company would comply with the Public Staff's recommendation. Therefore, the Commission concludes that Heater should reduce to writing all transactions with any affiliated companies and file the contracts with the Commission within 90 days of the effective date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 54 - 55

The evidence supporting these findings is contained in the testimony of Public Staff witness Fernald. Ms. Fernald recommended that Heater (1) begin accounting for CWIP in compliance with the Uniform System of Accounts and (2) begin recording the mark-up received from developers as CIAC. The Company did not contest Ms. Fernald's recommendations. Therefore, the Commission concludes that the Company should (1) begin accounting for CWIP in compliance with the Uniform System of Accounts and (2) begin recording the mark-up received from developers as CIAC.

IT IS, THEREFORE, ORDERED as follows:

1. That Heater shall adjust its water utility service rates and charges to produce, based on the adjusted test year level of operations, an increase in total water revenues of $1,489,192.

2. That the Schedule of Rates, attached hereto as Appendix A, is approved for service rendered by Heater. These rates shall become effective for service rendered on and after the 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 B, shall be delivered by Heater to all its water customers in conjunction with the next billing statement after the date of this Order.

4. That Heater shall reduce all transactions with any affiliated companies to writing and file the contracts with the Commission pursuant to G.S. 62-153 within 90 days of the effective date of this Order.

5. That Heater shall begin accounting for CWIP in compliance with the Uniform System of Accounts.

6. That Heater shall begin recording the mark-up received from developers as CIAC.

7. That Heater shall file two quality of service status reports for Wildcat Creek Subdivision. Heater shall file the first of such reports by August 31, 2005, and a final report by February 28, 2006. The Public Staff shall monitor this situation and shall file a response with the Commission within 30 days after the filing of each report.

8. That Heater shall file by August 31, 2005, a report indicating the systems that are still unapproved by DEH, the reasons the systems are unapproved, and the steps that shall be taken for approval of such systems. The Public Staff shall review such report and shall file a response with the Commission within 30 days after the filing of such report.

9. That the Joint Stipulation filed with the Commission in this matter is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

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SCHEDULE OF RATES
for
HEATER UTILITIES, INC.
for providing water and sewer utility service in
ALL ITS SERVICE AREAS IN NORTH CAROLINA

Except - Water utility service in all the former Alpha Utilities service areas (see Docket No. W-274, Sub 500)

WATER UTILITY SERVICE - Monthly

Metered Rates:

Base Charge, zero usage -	
<1" meter	$ 13.49
1" meter	33.73
1 1/2" meter	67.45
2" meter	107.92
3" meter	202.35
4" meter	337.25
6" meter	674.50
Commodity Charge, measured in gallons or cubic feet -	
Per 1,000 gallons	$ 3.94
Per 100 cubic feet	$ 2.95

Flat Water Rates – Monthly: [6/]

Residential	$ 37.91
Commercial at Residential Rate	$ 37.91
Commercial at Business Rate	$ 56.87
Commercial at Motel Rate	$170.60

Reconnection Charges: [7/]

If water service cut off by utility for good cause:	$35.00
If water service discontinued at customer's request:	$ 5.00

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Connection Charges:

Weatherstone Subdivision	$ 350.00
Wilson Farm Subdivision	$ 500.00
Woodlake Subdivision	
Per residential equivalent unit (REU)	$ 800.00
Irrigation meter installation fee	$ 300.00
Neuse Colony Subdivision	$2,000.00
The Gardens at Flowers Plantation, Eastlake at Flowers Plantation, Magnolia Place	$ 850.00

WATER AND SEWER – RATES

All other service areas -
3/4" x 5/8" meters -
For taps made to existing mains installed inside franchised service area: [1] — $ 800.00
For individual connections outside franchised service area: [2] — Actual cost of installation [3]
Meters exceeding 3/4" x 5/8" - — 120% of actual cost

Production and Storage Contribution in Aid of Construction Fee: [2]
For individual connections outside franchised service areas where lot owner has made no contribution in aid of construction toward production and storage facilities — $1,700 per REU

Meter Installation Fee: [4]	$70.00
Billing Service Charge: [5]	$ 2.00 per month per bill
New Customer Account Fee:	$20.00

SEWER UTILITY SERVICE - Monthly

Residential Service:

Windsor Oaks Subdivision: (Based on water usage)

Minimum Base Charge, zero usage	$ 28.40
Usage Charge, per 1,000 gallons	$ 2.79

(No sewer charge for water usage over 6,000 gallons per month)

Woodlake Subdivision: (Based on water usage)

Base Charge, zero usage -	
<1" meter	$ 25.74
1" meter	64.35
1 1/2" meter	128.70
2" meter	205.92
3" meter	386.10
4" meter	643.50
6" meter	1,287.00
Commodity Charge, measured in gallons or cubic feet -	
Per 1,000 gallons	$ 5.30
Per 100 cubic feet	$ 3.96

All Other Residential Service Areas:

	Former Mid-South Service Areas	Mobile Estates & Cross Creek MHP	All Other Service Areas
Flat Rate	$ 58.35	$ 41.81	$ 48.81

Commercial (Non-residential) Metered Service: (Metered rates, based on water usage)

Minimum Base Charge, based on meter size	Former Mid-South Service Areas	All Other Service Areas
<1" meter	$ 25.74	$ 21.52
1" meter	64.35	53.81
1 1/2" meter	128.70	107.62
2" meter	205.92	172.20
3" meter	386.10	322.87

4" meter	643.50	538.12
6" meter	1,287.00	1,076.24
Usage charge, per 1,000 gallons	$ 5.30	$ 4.43

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Commercial (Non-residential) Flat Rate Service:

	Former Mid-South Service Areas
Condominium residents at residential rate	$ 58.35
Commercial at residential rate	$ 58.35
Commercial at commercial rate	$ 175.05

Wastewater Treatment Plant Capacity Charge:
(Applicable to areas feeding into the Hawthorne Wastewater Treatment Plant in Wake County) — $1,080 per REU

Connection Charges:

Neuse Colony, The Gardens at Flowers Plantation, Bennett Place, Eastlake at Flowers Plantation, Magnolia Place -	$1,000.00
Woodlake Subdivision	$ 800.00 per REU

All other service areas -
None when tap and service line installed by developer.
Actual cost if Heater Utilities, Inc., makes tap or installs service line.

Reconnection Charges: [7/]

If sewer service cut off by utility for good cause by disconnecting water:	None
If sewer service cut off by utility for good cause by any method other than noted above:	Actual cost

Grease Traps:
Utility may require installation and/or proper operation of grease traps on grease producing commercial facilities. Failure to properly operate grease traps will result in disconnection of service pursuant to Commission Rule R10-16.

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New Customer Account Fee: $20.00
(If customer receives both water and sewer utility service from Heater, then the customer shall only be charged a new account fee for water.)

Reimbursement Charge for Damaged Sewer Lines - Crooked Creek Subdivision:
According to the Sewer Use and Maintenance Statement, which has been presented to all sewer customers for their information, sewer lines cut by the homeowner shall be repaired at the homeowner's expense.

WATER AND SEWER – RATES

Reimbursement Charge for Grinder Pump Repair - Crooked Creek Subdivision:

According to the Sewer Use and Maintenance Statement, which has been presented to all sewer customers for their information, the homeowner shall reimburse Heater Utilities, Inc., for damage to the pump and/or tank caused by willful or negligent discharge of the above items (items listed in the Statement) into the sewer system.

OTHER MATTERS

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.
Availability Rates:	
Woodlake Subdivision	$5.00 per month
	$3.75 per month

1/ In most areas, connection charges do not apply pursuant to contract and only the $70.00 meter installation fee will be charged to the first person requesting service (generally the builder). Where Heater must make a tap to an existing main, the charge will be $800.00, and where main extension is required, the charge will be 120% of the actual cost.

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2/ Individual connections outside franchised service areas may be made pursuant to this tariff in the following circumstances: (1) upon request of a bona fide customer as that term is defined in Commission Rule R7-16(a)(1); (2) the customer shall be located either within 100 ft. of a Franchised Service Area or located within 100 ft. of an existing Heater main; and (3) the request may come from no more than two customers located in the same area (requests for more than two connections require an application for a new franchise or a request for approval of a contiguous extension). To connect such a customer, Heater shall file a notice with the Commission in Docket No. W-274, Sub 193, at least 30 days before it intends to make the tap. This notice shall include an explanation of the circumstances requiring the tap and an 8.5" X 11" map showing the location of the tap in relation to Heater's existing main. If the Public Staff does not object to the tap within the 30 day period, or upon written notice within that period from the Public Staff that it will not object, Heater may proceed with the connection.

3/ Actual cost for such a connection shall include installation of a 6" or smaller main extension (if necessary), tap of the main, service line, road bore (if necessary), meter box, meter, backflow preventer (if necessary), and Heater's direct labor costs. Heater shall give a written cost quote to the customer(s) applying for connection before actually beginning the installation work.

4/ The fee will be charged only where cost of meter installation is not otherwise recovered through connection charges.

5/ Heater is authorized to include on its monthly water bill the charges resulting from sewer service provided by the Town of Cary, the Town of Fuquay-Varina, Wake County, and various Commission appointed emergency operators where specifically approved by the Commission. Heater will bill the Town of Cary, the Town of Fuquay-Varina, Wake County, or emergency operator $2.00 per month per bill for providing this service.

6/ The Utility, at its expense, may install a meter and charge the metered rate.

7/ When service is disconnected and reconnected by the same unit owner within a period of less than nine months, the entire flat rate and/or base charge rate will be due and payable before the service will be reconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-274, Sub 478, on this the 18th day of April, 2005.

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-274, SUB 478

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina	))))	NOTICE TO CUSTOMERS OF NEW RATES

BY THE COMMISSION: Notice is given that the North Carolina Utilities Commission has granted a rate increase to Heater Utilities, Inc., for water utility service in all its service areas (except those noted on the tariff sheet) in North Carolina. This decision was based on evidence presented at the hearings held on:

November 1, 2004, in Gastonia
November 2, 2004, in Concord
November 8, 2004, in Hickory
November 9, 2004, in Mt. Airy
November 30, 2004, in Raleigh
January 11, 2005, in Raleigh
February 9, 2005, in Raleigh

The new rates are as follows:

Water Utility Service:

Metered Rates:

Base Charge, zero usage –

<1" meter	$ 13.49
1" meter	33.73
1 1/2" meter	67.45
2" meter	107.92
3" meter	202.35
4" meter	337.25

6" meter	674.50
Commodity Charge, measured in gallons	
Per 1,000 gallons	$ 3.94

APPENDIX B
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Flat Water Rates – Monthly:

Residential	$ 37.91
Commercial at Residential Rate	$ 37.91
Commercial at Business Rate	$ 56.87
Commercial at Motel Rate	$170.60

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

DOCKET NO. W-274, SUB 478

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina) ERRATA ORDER

BY THE COMMISSION: On Appendix B to the Commission's Order in this docket dated April 18, 2005, the base charge of $13.49 for monthly metered water service for customers with less than a 1" meter was inadvertently omitted, and the Commission concludes that such error should be corrected as set forth in Appendix B attached hereto.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of April 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

dh042005.01

DOCKET NO. W-354, SUB 266

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc. of North Carolina, 2335 Sanders Road, Northbrook, Illinois, for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	)))))	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Monday, October 4, 2004 at 7:00 p.m.

Municipal Building, Meeting Room, 102 Town Hall Drive, Kill Devil Hills, North Carolina on Wednesday, October 6, 2004, at 7:00 p.m.

Jacksonville City Hall, Council Chambers, 211 Johnson Boulevard, Jacksonville, North Carolina on Thursday, October 7, 2004, at 7:00 p.m.

Charlotte-Mecklenburg Government Center, Chamber Meeting Room CH-14, 600 East Fourth Street, Charlotte, North Carolina on Thursday, October 14, 2004 at 7:00 p.m.

Buncombe County Courthouse, Courtroom, Fifth Floor, 60 Court Plaza, Asheville, North Carolina, on Wednesday, October 20, 2004, at 7:00 p.m.

Watauga County Courthouse, Courtroom #1, 842 West King Street, Boone, North Carolina on Thursday, October 21, 2004, at 7:00 p.m.

Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Tuesday, December 14, 2004 at 9:00 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Commissioner J. Richard Conder, Commissioner Robert V. Owens, Jr., and Commissioner Michael S. Wilkin[1]

APPEARANCES:

For Carolina Water Service, Inc. of North Carolina:

Edward S. Finley, Jr., Hunton & Williams, P.O. Box 109, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Gina C. Holt and Robert B. Cauthen, Jr., Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

[1] Commissioner Michael S. Wilkins left the Commission prior to decision-making in this proceeding.

WATER AND SEWER – RATES

BY THE COMMISSION: On May 29, 2003, Carolina Water Service, Inc. of North Carolina (CWS, Applicant, or Company) filed a letter notifying the Commission of its intent to file a general rate case as required by Commission Rule R1-17(a). On April 28, 2004, CWS and the Public Staff of the North Carolina Utilities Commission (Public Staff) filed a partial settlement in this and certain other proceedings in which CWS, the Public Staff and other parties stipulated to the appropriate capital structure, cost of capital and rate of return, and the allocation of certain rate case costs among various Utilities, Inc. subsidiaries, including CWS, for purposes of this and several other proceedings.

On July 7, 2004, CWS filed an application for a general rate increase in which it sought Commission approval to increase its rates for water and sewer service in its franchised service areas so as to produce a 28.07 percent increase in gross revenues compared to the level of gross revenues produced from existing rates.

By Order dated August 5, 2004, the Commission declared this matter to be a general rate case; suspended the proposed new rates for a period of up to 270 days pending further investigation and hearing; and scheduled this matter for hearing in Raleigh, Kill Devil Hills, Jacksonville, Charlotte, Asheville, and Boone, North Carolina. The Company was required to provide customer notice of the hearings and the proposed rate increase to all customers.

On August 18, 2004, CWS filed a motion to supplement its general rate case application in which the Company requested Commission approval to include two stand-alone utilities that are owned by Utilities, Inc. and that have rates that match CWS's uniform rates in this proceeding.

On August 20, 2004, the Commission entered an Order Accepting Revisions to Schedules and Modifying Notice in which the Commission allowed CWS's request to modify its application and required the alteration of the approved customer notice to reflect this amendment to the application.

On September 14, 2004, CWS filed a Certificate of Service indicating that the public notice had been provided in accordance with the Commission's procedural order.

Public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this case:

October 4--Raleigh	George Pence, Lawrence Lehr, Susan Bourland, Florence Keith, Kaye Moore
October 6--Kill Devil Hills	Alicia McDonald, Pat Couper, Jim O'Connell, Suzanne Davis, Hugh McCain, Phillip Dombeck
October 7--Jacksonville	Lena Butler, Donald Shipley, Gwen Slade
October 14--Charlotte	Steven Smith, Perry Rivers, Robert Sitze, Ken Goodnight, Lynda Cayax, Susan Noel, Cline McGee, Steve White, Susan Hambright, Jeffrey Adair, Don Cherry

October 20--Asheville	Richard Braby, Warren Johnson, Dieter Hammer, James Hemphill, Bill West, Skip Williams, Ruth Hellerman, Richard Engle, James Tanner
October 21--Boone	William Kaiser, James Wood, Harvey Bauman, Larry Finnegan, Alex Popper
December 14--Raleigh	Steven Smith

No party filed an intervention petition in the form required by Commission Rules R1-5 and R1-19.

On October 15, 2004, CWS filed the testimony and exhibits of Steven M. Lubertozzi, Director of Regulatory Accounting for CWS. On November 19, 2004, the Public Staff filed the testimony and exhibits of Katherine A. Fernald, Supervisor, Water Section, Accounting Division, Windley E. Henry, Staff Accountant, Accounting Division, John R. Hinton, Financial Analyst, Economic Research Division, and Jay B. Lucas, Utilities Engineer, Water Division. On December 3, 2004, CWS filed the rebuttal testimony and exhibits of Carl Daniel, Regional Vice-President for CWS, Steven M. Lubertozzi, and Kirsten E. Weeks, Senior Regulatory Accountant for CWS.

This matter came on for evidentiary hearing in Raleigh as scheduled on December 14-15, 2004. The Applicant presented the direct testimony of Steven Lubertozzi. The Public Staff presented the testimony of its witnesses Lucas, Hinton, Henry, and Fernald. The Company presented the rebuttal testimony of Company witnesses Daniel, Weeks, and Lubertozzi.

Subsequent to the hearing there were filings made by the Public Staff and the Company pursuant to the request of the Chairman at the conclusion of the December 14 hearing.

On January 4, 2005, Public Staff witness Fernald filed her late-filed exhibit.

On January 5, 2005, the Company filed revised rebuttal exhibits and schedules and the late-filed exhibits of Company witnesses Lubertozzi and Weeks. The Company also filed as a late-filed exhibit a memorandum from the office of PricewaterhouseCoopers accounting firm. On January 7, 2005, the Company filed amendments to the revised exhibits and schedules of Steven Lubertozzi and Kirsten Weeks that it had previously filed. On January 11, 2005, CWS filed the Affidavit of Carl Daniel.

On January 12, 2005, the Public Staff filed revised exhibits and schedules and the late-filed exhibits and schedules of Public Staff witnesses Fernald, Henry and Lucas.

Based on the application, the testimony and exhibits, and the entire record in this proceeding, the Commission makes the following

WATER AND SEWER – RATES

FINDINGS OF FACT

General Matters

1. CWS 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. CWS 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.

3. The test period appropriate for use in this proceeding is the twelve months ended December 31, 2003, updated to June 30, 2004.

4. CWS operates 81 water utility systems and 38 sewer utility systems, some of which serve multiple subdivisions. These water and sewer utility systems are spread throughout North Carolina. All of the service areas are mainly residential; however, some have retail and commercial customers receiving service.

5. According to CWS's billing data, there were approximately 22,200 end-of-period residential equivalent units (REUs) receiving water utility service and approximately 14,636 end-of-period REUs receiving sewer utility service.

6. There were approximately 1,820 end-of-period water availability customers in the Carolina Forest and Woodrun service areas.

7. CWS provides metered water utility service to all of its water customers except for approximately 1,233 unmetered or flat rate REUs in the following service areas: Sherwood Forest, Misty Mountain, Crystal Mountain, Mount Mitchell Lands, Watauga Vista, High Vista, High Meadows, Powder Horn, and part of Sugar Mountain.

8. CWS provides flat rate service to all of its residential sewer customers and provides metered sewer service to all of its commercial sewer customers except for the former Mercer Environmental sewer systems. CWS acquired the Mercer sewer systems in July 2003, and the Commission granted separate rates based on the existing Mercer rates in effect before the acquisition.

9. CWS's existing and proposed water service rates are as follows:

Monthly Metered Service:

		Existing	CWS's Proposed
Base Facilities Charges (zero usage)			
A.	Residential Single Family Residence	$ 10.10$	13.75

B.	Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 10.10$	13.75
C.	Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (As in a Condominium Complex)	$ 9.10	$ 12.39
D.	Commercial and Other (Based on Meter Size): 5/8" x 3/4" meter	$ 10.10	$ 13.75
	1" meter	$ 25.25	$ 34.38
	1-1/2" meter	$ 50.50	$ 68.76
	2" meter	$ 80.80	$110.02
	3"meter	$ 151.50	$206.28
	4" meter	$ 252.50	$343.81
	6" meter	$ 505.00	$687.61
Usage Charge:			
A.	Treated Water/1,000 gallons	$ 3.03	$ 4.02
B.	Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.00	$ 2.66
Monthly Flat Rate Service:			
A.	Single Family Residential	$ 21.65	$ 29.48
B.	Commercial/SFE (SFE is a single family equivalent)	$ 21.65	$ 29.48
Availability Rates (semi-annual):	Applicable only to property owners in Carolina Forest and Woodrun Subdivision in Montgomery County	$ 12.00	$ 16.34

10. The miscellaneous charges and fees of the Company will remain unchanged.

11. The management fees of the Company will remain unchanged.

12. CWS's existing and proposed sewer service rates are as follows:

Monthly Metered Service: Commercial and Other Non-Residential Users:

A. Base Facility Charges (based on meter size with zero usage)

	Existing	CWS's Proposed
5/8" x 3/4" meter	$ 10.10	$ 12.90
1" meter	$ 25.25	$ 32.20
1-1/2" meter	$ 50.50	$ 64.40
2" meter	$ 80.80	$103.00

	3" meter	$151.50	$193.10
	4" meter	$252.50	$321.80
	6" meter	$505.00	$643.70
B.	Usage Charge/1,000 gallons (based on metered water usage)	$ 4.55	$ 5.80
C.	Minimum Monthly Charge	$ 30.55	$ 38.94
D.	Sewer customers who do not receive water service from the Company (per SFE or Single Family Equivalent)	$ 30.55	$ 38.94

Monthly Flat Rate Service:

Per Dwelling Unit	$ 30.55	$ 38.94

Monthly Collection Service Only
(When sewage is collected by utility and transferred to another entity for treatment)

A.	Single Family Residence	$ 11.00	$ 14.00
B.	Commercial/SFE	$ 11.00	$ 14.00

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 4.60	$ 5.90
Usage Charge/1,000 gallons (based on metered water usage)	$ 4.01	$ 5.11

Regalwood and White Oak Estates Subdivision Service Areas:
A. Monthly Flat Rate Sewer Service:

Residential Service	$ 25.75	$ 38.94
White Oak High School	$956.00	$1,218.50
Child Castle Daycare	$122.56	$ 156.20
Pantry	$ 67.18	$ 85.60
Circle K	$247.85	$ 315.90

13. CWS's water and sewer systems are adequately maintained and operated and CWS is providing adequate water and sewer service.

Rate Base

14. The appropriate level of total plant in service is $82,973,405, of which $49,093,439 is applicable to water operations and $33,879,966 is applicable to sewer operations.

15. The appropriate level of accumulated depreciation for use in this proceeding is $13,898,212, of which $7,622,463 is applicable to water operations and $6,275,749 is applicable to sewer operations.

16. The appropriate depreciation rate for computer equipment additions recorded after June 30, 2004, is 12.50%.

17. The appropriate levels of cash working capital are $425,911 for water operations and $422,603 for sewer operations.

18. The appropriate level of contributions in aid of construction (CIAC), net of amortization, for use in this proceeding is $18,536,122 for water operations and $15,416,949 for sewer operations.

19. In the Quail Ridge system, the Company undercollected connection fees by $250 per tap from 1993 to 1996. In 1996, the Company realized its error, and began collecting the correct fee.

20. It is the responsibility of a utility company's management to collect its authorized rates, including connection charges and plant modification fees (hereinafter referred to as connection fees) and management fees.

21. On October 12, 1992, the Commission issued an order in Docket No. W-354, Sub 111 (Sub 111) requiring that the Company file all new contracts within 30 days from signing with the Chief Clerk of the Commission.

22. The order issued in Sub 111 also required that the Company obtain prior approval to deviate from its uniform connection fees in both existing and new service areas.

23. Since October 12, 1992, the Company has waived connection fees for an area in Mt. Carmel, and in the Windward Cove and Lamplighter Village South systems, without obtaining prior Commission approval to do so.

24. Under the agreement with Huber Construction in the Mt. Carmel service area, the Company has collected a $750 connection fee on behalf of the Buncombe/Asheville sewer district (MSD), and has collected for itself a connection fee of $1,055, which is $45 less than the uniform connection fee. The Company did not obtain prior Commission approval to vary from its authorized connection fee in this system.

25. In its order issued on March 22, 1994, in Docket No. W-354, Sub 118 (Sub 118), the Commission required that CWS, once and for all, conform its tariffs to reflect the connection fees actually being charged. Furthermore, the Commission stated that future deviations would not be tolerated.

26. It is the responsibility of the Company's management to comply with the Commission's orders and tariffs.

27. In the systems where the Company failed to collect its authorized uniform connection fees, and failed to obtain prior Commission approval to vary from those fees, the uniform connection fees should be imputed.

28. On August 27, 1996 the Commission issued an order in Docket No. M-100, Sub 113, requiring that all water and sewer companies cease collecting gross-up on CIAC received after June 12, 1996.

29. The August 27, 1996, order also required that all water and sewer companies which had collected gross-up after June 12, 1996, refund any amounts collected to the contributors with 10% interest per annum and file a notarized report with the Commission of the refunds made.

30. The Company failed to file the notarized report on the gross-up refunds as required in the August 27, 1996 order.

31. Although the contracts for Cambridge, Southwoods, Matthews Commons, Lamplighter Village South, and Bradford Park did not specifically list the amount of gross-up included in the total connection fee, these contracts were entered into during the time that gross-up was required, and the fees set forth in the contracts included gross-up.

32. The Company has collected gross-up on CIAC collected after June 12, 1996, in the Cambridge, Southwoods, Matthews Commons, Lamplighter Village South, and Bradford Park systems.

33. It is appropriate to require the Company to refund the gross-up collected after June 12, 1996 to the current property owners.

34. An interest rate of 10%, compounded annually, continues to be a just and reasonable rate to use in calculating interest on utility refunds.

35. Since the Company no longer has customer records for the systems that it has sold, it would be difficult to refund the gross-up collected in these systems. Therefore, these over-collections should be treated as cost-free capital in this and all future proceedings.

36. For some systems, the Company has collected reservation of capacity fees from developers for plant costs and capacity.

37. CWS has failed to record reservation of capacity fees in CIAC on its books, as required by the Commission.

38. Just as the cost of money used by the Company during construction is recognized through the calculation of an allowance for funds used during construction (AFUDC), it is also appropriate to recognize the fact that the Company has the use of the reservation of capacity fees by including these fees in CIAC in this case.

39. The management fee for Covington Cross sewer operations is $100 per lot.

40. The appropriate amount of accumulated deferred income taxes (ADIT) to deduct from rate base in this proceeding is $2,920,893 for water operations and $1,671,871 for sewer operations.

41. CWS has included payments received by the Company in 2001, 2002, and 2003 as plant modification fees as taxable income for tax purposes.

42. CWS has appropriately accounted for the plant modification fees.

43. The appropriate amount of ADIT related to plant modification fees is $554,465 for water operations and $422,257 for sewer operations.

44. The appropriate amount of ADIT related to rate case expense to deduct from rate base in this proceeding is $34,270 for water operations and $20,651 for sewer operations.

45. The appropriate amount of ADIT related to deferred maintenance costs to be deducted from rate base in this proceeding is $136,231 for water operations and $82,088 for sewer operations.

46. The amount of pro forma plant additions included in the calculation of ADIT related to depreciation should not be reduced by the amount of retirements.

47. The appropriate level of deferred charges for use in this proceeding is $708,721, of which $482,129 is applicable to water operations and $226,592 is applicable to sewer operations.

48. The amount of unamortized deferred charges related to maintenance items recommended by the Public Staff is appropriate for use in this proceeding.

49. Based on a three year amortization period and total rate case costs found reasonable elsewhere in this order, the unamortized balance of rate case expense to include in deferred charges is $142,452.

50. The appropriate level of cost-free capital for use in this proceeding is $104,308, of which $48,481 is applicable to water operations and $55,827 is applicable to sewer operations.

51. CWS's reasonable rate base used and useful in providing service is $30,372,584, consisting of utility plant in service of $82,973,405, cash working capital of $848,514, Water Service Corporation (WSC) rate base of $256,584, pro forma plant of $3,597,452, and deferred charges of $708,721, reduced by accumulated depreciation of $13,898,212, CIAC, net of amortization, of $33,953,071, advances in aid of construction of $44,780, ADIT of $4,592,764, customer deposits of $392,487, gain on sale and flow back taxes of $289,628, plant acquisition adjustment of $1,880,811, excess capacity of $122,896, excess book value of $2,296,948, cost-free capital of $104,308, and allocation of CWS office plant costs of $436,187.

Revenues

52. The appropriate level of end-of-period water service revenue at existing rates is $6,896,512. The appropriate level of end-of-period sewer service revenue at existing rates is $5,356,689.

53. It is appropriate to make adjustments to water consumption due to the abnormal usage patterns during the test year.

54. The only billing record data available from the Company is for the years 1992, 1996, 2001, 2002, 2003, and part of 2004. Data from the annual reports is available, but this information is not as accurate as the Company's billing records.

55. Averaging water data from 2001, 2002, and 2003 yields 5,300 gallons per month per water REU. Averaging sewer data from 2001, 2002, and 2003 yields 8,233 gallons per month per metered sewer REU.

56. Based on an average consumption of 5,300 gallons per month per water REU, the water consumption factor for use in this proceeding is 8.1%.

57. The appropriate level of miscellaneous revenue to include in this proceeding is $271,553, of which $208,366 relates to water operations and $63,187 relates to sewer operations.

58. Revenues from antenna space rentals are incidental revenues, and should be included in miscellaneous revenue in this case.

59. The appropriate level of uncollectibles is $64,407, of which $36,552 is applicable to water operations and $27,855 is applicable to sewer operations.

60. Total revenue to be reflected in this proceeding is $12,460,347, of which $7,068,326 is applicable to water operations and $5,392,021 is applicable to sewer operations. Gross service revenue is $12,253,201, of which $6,896,512 is applicable to water operations and $5,356,689 is applicable to sewer operations. Miscellaneous revenue is $271,553, of which $208,366 relates to water operations and $63,187 relates to sewer operations. Total revenue is reduced by uncollectibles of $64,407, of which $36,552 is applicable to water operations and $27,855 is applicable to sewer operations.

Customer Growth

61. The appropriate level of customer growth for use in this proceeding is 5.8% for water operations and 17.6% for sewer operations.

Maintenance Expenses

62. The appropriate level of salaries and wages to include in operation and maintenance expense is $2,200,663, of which $1,373,215 is applicable to water operations, and $827,448 is applicable to sewer operations.

63. The salaries for fifteen new certified operators should be included in this case.

64. The appropriate amount of purchased water expense is $395,489 before any annualization and inflation adjustments.

65. The appropriate level of total maintenance and repairs for use in this proceeding is $2,026,450, of which $577,333 is applicable to water operations and $1,449,117 is applicable to sewer operations.

66. The appropriate level of deferred expenses to include in maintenance and repairs is $194,976, of which $129,961 is applicable to water operations and $65,015 is applicable to sewer operations.

67. The Company has failed to provide evidence supporting any additional deferred expenses above the amount included by the Public Staff in its final schedules.

68. The appropriate amount of sludge hauling expense is $865,918 before any inflation adjustment.

69. Maintenance expenses should be reduced for operating expenses charged to plant of $910,414, of which $568,099 is applicable to water operations and $342,315 is applicable to sewer operations.

70. The appropriate level of outside services - other for use in this proceeding is $181,738, of which $128,284 is applicable to water operations and $53,454 is applicable to sewer operations.

71. One-half of the legal fees for Pine Knoll Shores should be included in maintenance expenses in this proceeding.

72. The appropriate level of operation and maintenance expenses is $5,878,350, of which $3,028,299 is applicable to water operations and $2,850,051 is applicable to sewer operations.

<u>General Expenses</u>

73. The appropriate level of salaries and wages to include in general expenses is $696,863, of which $434,843 is applicable to water operations and $262,020 is applicable to sewer operations.

74. It is appropriate to correct general salaries for reclassification of an operator.

75. The salary of a project manager should be included in this proceeding.

76. The appropriate level of rate case expense to include in this proceeding is $71,226, of which $44,445 relates to water operations and $26,781 relates to sewer operations.

77. An adjustment to legal fees for this proceeding is appropriate.

78. The appropriate amortization period for rate case expense is three years.

79. It is appropriate to include health insurance, pension and 401(k) costs for fifteen new operators and a project manager.

80. The appropriate level of pension and other benefits to include in this proceeding is $613,126, of which $382,591 relates to water operations and $230,536 relates to sewer operations.

81. The appropriate annualization adjustment to be made in this proceeding is $204,159 for water operations and $329,769 for sewer operations.

82. The appropriate inflation adjustment to be made in this proceeding is $175,557, of which $83,302 is applicable to water operations and $92,255 is applicable to sewer operations.

83. The appropriate level of general expenses is $3,038,065, of which $1,730,751 is applicable to water operations and $1,307,315 is applicable to sewer operations.

Depreciation and Taxes

84. The appropriate level of depreciation expense for use in this proceeding is $1,109,393, of which $731,150 is applicable to water operations and $378,243 is applicable to sewer operations.

85. The appropriate level of payroll taxes to include in this proceeding is $209,134, of which $139,148 relates to water operations and $69,986 relates to sewer operations.

86. Based on the other findings and conclusions set forth in this Order, the appropriate level of state income taxes is $16,046 for water operations and $0 for sewer operations.

87. Based on the other findings and conclusions set forth in this Order, the appropriate level of federal income taxes is $67,686 for water operations and $0 for sewer operations.

88. The appropriate level of depreciation and taxes for use in this proceeding is $2,176,186, of which $1,340,556 is applicable to water operations and $835,630 is applicable to sewer operations.

Overall Cost of Capital

89. The appropriate capital structure to employ for purposes of this proceeding consists of 57.63% debt and 42.37% equity. The embedded cost of debt associated with this capital structure is 7.28%.

90. The cost of common equity capital to CWS for purposes of this proceeding is 10.7%.

91. The overall fair rate of return that the Company should be allowed the opportunity to earn on its rate base is 8.73%.

Rates, Fees and Other Matters

92. The Commission finds that the Company's rates should be changed to amounts, which, after pro forma adjustments, will produce an increase in total annual revenue of $2,171,390. This increase will allow CWS the opportunity to earn an 8.73% overall return on its rate base, which the Commission has found to be reasonable upon consideration of the findings in this Order.

93. The connection charges and plant modification fees currently approved by the Commission are set forth in the tariff sheets attached as Appendix A to this Order.

94. The Company should be responsible for installing all meters, and should no longer accept meters from developers. When meters are installed, the Company is authorized to charge a meter fee of $50 for 5/8 or 3/4 inch meters, and actual cost for meters greater than 5/8 or 3/4 inch, for all metered water connections.

95. The metering of unmetered water systems should be accomplished as follows:

a. CWS should solicit preliminary estimates from contractors to be used as a basis for determining the approximate cost of installing meters.
b. This information should be provided to each homeowners association in the unmetered areas.
c. If the homeowners association requests that meters be installed, CWS should solicit bids from contractors.
d. The homeowners association should be allowed to review the final bid amount.
e. If the homeowners association approves the project based on the final bid amount, CWS should award the contract within 30 days of final approval from the homeowners association and request approval from the Commission for an assessment to recover the cost.

96. Management fees, reservation of capacity fees, payments for main extensions, and other monies received to offset plant costs are CIAC, and should be recorded as such on the Company's books and records.

97. It is appropriate for the Company to make entries on its books to reflect the amount of CIAC found reasonable by the Commission in this case.

98. It would be useful to the Company and both the Commission and Public Staff if there were separate subaccounts for each type of CIAC received by the Company.

99. Both depreciation expense and amortization of CIAC recorded on the Company's books should be calculated based on the actual amounts of plant and CIAC for that period.

100. Because the allocation of pension and 401(k) costs has been and will be corrected in rate cases, it is unnecessary to require the Company to revise its allocation of pension and 401(k) costs on its books.

101. The Company should begin recording revenues from antenna space rentals in water operating revenues under Account 472 - Rents from Water Property.

102. The receipt of plant modification fees should be recognized in the calculation of AFUDC.

103. The sludge hauling and other services provided by Bio-Tech, Inc. (Bio-Tech) to CWS are affiliated transactions covered by G.S. 62-153, and a contract between Bio-Tech and CWS should be filed with the Commission within 30 days of the effective date of this Order.

104. Utilities, Inc. should also file contracts covering the affiliated transactions between Bio-Tech and the North Carolina regulated companies other than CWS within 30 days of the effective date of this Order. The contract for each regulated company should be filed under the applicable docket number for that company.

105. The Company should file all contracts or agreements it has with developers that have not been previously filed with the Chief Clerk of the Commission within 90 days of the effective date of this Order, including but not limited to the contracts for

Southwoods / Brandywine, Windward Cove; Mt. Carmel - Harmony, Mr. Carmel - Huber Construction, Lamplighter Village South - Marshall, and Bent Tree (sewer operations).

106. The Company should file all future contracts and agreements within 30 days of signing or agreement.

107. The Company should evaluate its current practices and prepare a new procedure that ensures that the Company will comply with the rules and regulations of the Commission, in particular the rules concerning contiguous extensions and franchises. The Company should file its procedure with the Commission within 60 days of the effective date of this Order.

108. It is not appropriate to impose any penalties as recommended by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 3

These findings are in the Commission's official records and in the Company's application. They are essentially informational, procedural, and jurisdictional in nature, and matters that they involve are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 - 12

The evidence supporting these findings is contained in the testimony of Public Staff witness Lucas. The Company did not contest these findings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding is contained in the testimony of Public Staff witness Lucas and Company witness Daniel. Witness Lucas contacted the regional engineers in each of the various regional offices of the Department of Environment and Natural Resources, Division of Environmental Health, and each indicated that, aside from occasionally exceeding various water quality parameters, CWS was substantially in compliance with the regulations governing community water systems. Witness Lucas inspected 17 water systems. At each location, he found the well houses, treatment facilities, and storage facilities to be well maintained.

Witness Lucas also contacted each of the regional engineers of the Department of Environment and Natural Resources, Division of Water Quality (DWQ), and each indicated that he had a good working relationship with CWS. Other than occasional violations of effluent limits, none of the regional engineers indicated that any of the sewer utility systems were in noncompliance with DWQ's regulations. Witness Lucas inspected 16 sewer utility systems operated by CWS and concluded that each facility was being properly operated and maintained.

The Public Staff received numerous customer complaint letters. A large number of the letters objected to the rate increase itself. Some indicated water quality and water pressure problems. All of the water quality complaints, except for one, were for aesthetic and not for health concerns. These complaints are similar to those made by customers at the public hearings held in various locations across the state in October 2004. The Public Staff recommended that CWS address the customer complaints in its rebuttal and describe the actions it is taking to resolve these complaints.

The one complaint regarding health concerns was made by a customer in Riverpointe Subdivision in Mecklenburg County. This water system has aesthetic problems, pressure problems, and has exceeded the limits for radioactivity. CWS has addressed the high radioactivity by improving its water softening system. More testing over a period of time is needed before the Commission can consider the radioactivity problem solved. This issue is also part of the formal complaint filed by customers in Docket No. W-354, Sub 279, and the aesthetic and pressure problems will be addressed by the Commission in that docket.

Company witness Carl Daniel addressed customer complaints in his rebuttal testimony and indicated that the Company has either contacted or attempted to contact all of the customers who testified at the public hearings.

Based on the foregoing, the Commission concludes that CWS's water and sewer systems are adequately maintained and operated.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 - 51

The evidence supporting these findings is contained in the testimony of Public Staff witnesses Lucas, Fernald and Henry and of Company witnesses Daniel, Weeks and Lubertozzi. The following tables summarize the amounts which the Company and the Public Staff contend are the proper levels of rate base to be used in this proceeding:

WATER OPERATIONS

Item	Company	Public Staff	Difference
Plant in service	$49,093,439	$49,093,439	$ 0
Accumulated depreciation	(7,622,380)	(7,622,463)	(83)
Cash working capital	424,033	387,569	(36,464)
Contributions in aid of construction	(18,444,506)	(18,536,122)	(91,616)
Advances in aid of construction	(29,680)	(29,680)	0
Accumulated deferred income taxes	(2,742,295)	(3,396,528)	(654,233)
Customer deposits	(244,912)	(244,912)	0
Gain on sale and flow back taxes	(196,947)	(196,947)	0
Plant acquisition adjustment	(1,166,758)	(1,166,758)	0
Water Service Corporation	160,108	160,108	0
Pro forma plant	1,511,794	1,511,794	0
Deferred charges	484,765	497,569	12,804
Excess capacity	(122,896)	(122,896)	0
Excess book value	(969,448)	(969,448)	0
Cost-free capital	(27,934)	(48,481)	(20,547)
Allocation of CWS office plant cost	(272,181)	(272,181)	0
Original cost rate base	$19,834,202	$19,044,063	$ (790,139)

SEWER OPERATIONS

Item	Company	Public Staff	Difference
Plant in service	$33,879,966	$33,879,966	$ 0
Accumulated depreciation	(6,275,697)	(6,275,749)	(52)
Cash working capital	419,661	383,757	(35,904)
Contributions in aid of construction	(15,366,589)	(15,416,949)	(50,360)
Advances in aid of construction	(15,100)	(15,100)	0
Accumulated deferred income taxes	(1,652,408)	(2,033,281)	(380,873)
Customer deposits	(147,575)	(147,575)	0
Gain on sale and flow back taxes	(92,681)	(92,681)	0
Plant acquisition adjustment	(714,053)	(714,053)	0
Water Service Corporation	96,476	96,476	0
Pro forma plant	2,085,658	2,085,658	0
Deferred charges	238,474	235,896	(2,578)
Excess capacity	0	0	0
Excess book value	(1,327,500)	(1,327,500)	0
Cost-free capital	0	(55,827)	(55,827)
Allocation of CWS office plant cost	(164,006)	(164,006)	0
Original cost rate base	$10,964,626	$10,439,032	(525,594)

As shown in the preceding tables, the Public Staff and the Company agree on the levels of plant in service, advances in aid of construction, customer deposits, gain on sale, plant acquisition adjustment, Water Service Corporation rate base, pro forma plant, excess capacity, excess book value, and allocation of CWS office plant cost. Therefore, the Commission finds and concludes that the levels agreed to by the parties for these items are appropriate for use in this proceeding.

ACCUMULATED DEPRECIATION

The only difference between CWS and the Public Staff regarding accumulated depreciation is due to an error made by the Company in calculating accumulated depreciation on computer related equipment recorded on the books after June 30, 2004, through December 14, 2004. The Company calculated accumulated depreciation on computer equipment additions recorded after June 30, 2004, using the composite depreciation rates of 2.12% for water operations and 2.01% for sewer operations. In its original application, CWS calculated depreciation on test year computer equipment using a rate of 12.50%. Public Staff witness Henry calculated accumulated depreciation on all computer related equipment, including amounts added after June 30, 2004, using the depreciation rate of 12.50% for both water and sewer operations.

There is no dispute between the parties on the appropriate depreciation rates to use in this proceeding. CWS simply applied the wrong depreciation rate to computer related equipment. Correction of this error results in accumulated depreciation of $13,898,212, of which $7,622,463 is for water operations and $6,275,749 is for sewer operations.

CASH WORKING CAPITAL

The Company and the Public Staff have recommended different amounts of cash working capital as a result of having recommended different levels of expenses and certain taxes. Based upon conclusions regarding the appropriate level of expenses and taxes, the Commission determines that the appropriate levels of cash working capital are $425,911 for water operations and $422,603 for sewer operations.

CONTRIBUTIONS IN AID OF CONSTRUCTION

The parties disagree on the amount of CIAC, net of amortization. The Public Staff recommends an amount of $18,536,122 for water operations, which is $91,616 greater than the Company's proposed amount of $18,444,506. The Public Staff also recommends an amount of $15,416,949 for sewer operations, which is $50,360 more than the Company's proposed amount of $15,366,589. The differences in the level of CIAC recommended by the parties consist of the following items:

Item	Water	Sewer
Impute tap fees	$ 35,664	$ 83,942
Refund gross-up	(71,403)	(158,448)
Refund Bradford Park overcollection	(14,707)	(31,933)
Reservation of capacity fees	97,921	109,565
Management fees	44,144	47,232
Rounding differences	(3)	2
Total	$ 91,616	$ 50,360

Impute Tap Fees

The Public Staff has recommended that CIAC be increased by $119,606 to impute connection fees. These adjustments fall into three categories: (1) the Quail Ridge system where the Company collected the wrong fee in error, (2) the Mt. Carmel - Carlson agreement, Windward Cove, and Lamplighter Village South systems where the Company varied from its authorized uniform fees, and (3) the Mt. Carmel - Huber agreement where the Company varied from its uniform fees and the parties disagree on the actual amount of fee collected for CWS.

For the Quail Ridge system, Public Staff witness Fernald testified that from 1993 to 1996, the Company collected only $500 per tap, which is $250 less than its authorized fee. In 1996, the Company corrected its error and began collecting the correct amount of connection fee. Witness Fernald made an adjustment to impute the difference of $250 per tap.

In her rebuttal testimony, Company witness Weeks opposed the Public Staff's adjustment to impute connection fees for Quail Ridge. Although witness Weeks acknowledged that the Company undercollected connection fees in Quail Ridge, she stated that attribution of the undercollection was not justified since the Company's failure to collect the authorized connection fee was inadvertent. Witness Weeks further stated that, of the many connection fees the Company collects each month, from time to time it will make mistakes. Witness Weeks also pointed out that the Company discovered and rectified its undercollections after 1996. In the alternative, witness Weeks stated that if the Commission should impute the difference in connection fees, then the Company should be allowed to assess the current property owners for the amount undercollected.

The Commission concludes that the Public Staff's adjustment to impute connection fees in Quail Ridge is appropriate, but the Company's request to assess its customers for its mistake is not appropriate. The applicable statute to be used in this proceeding is G.S. 62-139, which states, "No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed by the Commission, nor shall any person receive or accept any service from a public utility for a compensation greater or less than that prescribed by the Commission." It is clear from this statute that the Company has a duty to charge only fees authorized by the Commission. Although the statute requires that customers not receive a service for less than an amount prescribed by the Commission, it does not address a procedure to be followed if a customer is undercharged or provide a penalty for undercharges of the utility customer. In contrast, G.S. 62-139(b) provides the procedure to be followed for the refunding of overcharges made by a public utility and prescribes a penalty for overcharges that are not timely refunded. Therefore, G.S. 62-139 does not support the Company's proposal to assess customers for undercharges. Additionally, there is no evidence that the customers were even aware that they were being charged fees that were less than those authorized by the Commission, whereas the Company discovered its mistake over eight years ago.

In light of the foregoing, the Commission concludes that it should not approve the Company's proposal to assess customers for undercharges. Additionally, the Commission concludes that it is the responsibility of management of the utility company to collect its authorized rates, including connection fees; that it is not the responsibility of the ratepayers to keep up with the fees that the Company is authorized to collect; that there is no evidence that the customers were even aware that they were being undercharged; and, finally, that the ratepayers should not be required to pay rates to allow a return on plant investment that should have been recovered through authorized connection fee collections. The Commission further concludes that since the Company discovered its error over eight years ago and did not propose an assessment at that time, it should be estopped from assessing its customers, as it would not be equitable to hold otherwise.

The Public Staff also imputed connection fees related to an agreement with Mr. Mark Carlson (Carlson agreement) for an area in Mt. Carmel, the Windward Cove system, and the Lamplighter Village South system. Public Staff witness Fernald testified that in the December 8, 1993, Carlson agreement and the November 18, 1993, Windward Cove agreement the Company waived connection fees, subject to approval of the North Carolina Utilities Commission. However, these agreements were never filed with the Commission for approval, even though the order granting a rate increase issued in the Sub 111 rate case required that all contracts with developers be filed with the Commission within 30 days of signing. Witness Fernald further testified that the Company failed to disclose that it had entered into agreements waiving the connection fees in Mt. Carmel and Windward Cove when it filed its amended tariff as required by the Commission in the tap fee investigation in Sub 118. As to Lamplighter Village South, witness Fernald testified that on March 29, 2000, the Company sent a letter to Marshall Properties agreeing to waive tap fees, and that this agreement to waive tap fees was never filed with the Commission. Since the Company failed to file these agreements with the Commission for approval and deviated from its authorized tariff by charging fees consistent with those set out in these contracts, Public Staff witness Fernald made an adjustment to impute the authorized uniform connection fees of $1,100 per connection in these systems.

In her rebuttal testimony, Company witness Weeks opposed the Public Staff's adjustment, stating that the Commission has ruled that the terms of the contract control the requirement to charge connection fees and that the fees should not be imputed because the Company followed its contract and did not resort to the uniform tariff. Witness Weeks further stated that it was unclear in 1993 whether the Company had to file an agreement such as the Carlson agreement in advance for approval, since this was not a new subdivision or area for which a certificate application or contiguous extension notification would be necessary. Witness Weeks also testified that the Public Staff's adjustment was unjustified simply because the Company failed to file a letter and that the Company should not be punished for its failure to do so. Witness Weeks also pointed out that in the Windward Cove and Lamplighter Village agreements, the developer contributed all the facilities to CWS, and therefore, the developer provided additional consideration. Finally, witness Weeks stated that the Commission's order in Sub 128 placed the burden on both CWS and the Public Staff to conform CWS's tariffs to the terms of arrangements and that the Public Staff has been aware of this letter for 11 years. Company witness Lubertozzi testified that the Commission had issued requirements concerning the filing of contracts in Sub 111, but all of the procedures were under review in Sub 118.

First, the Commission does not agree that it was unclear whether contracts or agreements should have been filed in 1993. In the Sub 111 order, which was issued on October 12, 1992, the Commission ordered the following:

> Also, all new contracts in the future should be filed within 30 days from signing. All contracts should be filed <u>with the Chief Clerk of the Commission</u> and a copy of each contract should be served on the Public Staff. If any agreements are reached with developers regarding the provision of utility service, but are not written or signed prior to being acted on, CWS shall file with the Commission a detailed written description of the agreement within 30 days of entering into the agreement.
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> . . .
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> The Commission agrees with the Public Staff on this issue and concludes that the Company should charge the uniform tap fee and plant modification fee in all of its service areas unless it receives <u>prior</u> approval to deviate from the uniform fees. This requirement should apply to both existing and new service areas. The filing by CWS of contracts that provide for non-uniform fees does not constitute Commission approval of such fees.

82 Report of the NCUC Orders and Decisions 387, 502 (1992)

At the time the Commission issued the Sub 111 order requiring the filing of all contracts or agreements, the Commission had already, on August 19, 1992, issued an order initiating the tap fee investigation in Sub 118, so clearly the investigation initiated in Sub 118 did not remove the requirement to file contracts. If anything, the Sub 118 proceeding should have made the Company even more aware of the importance of filing contracts and obtaining approval from the Commission to vary from the uniform fees. The Company did not except to the filing requirement set forth in the Sub 111 order and should have known that the requirement remained in force.

The requirement to file contracts in Sub 111 applies to all developer contracts, and even goes so far as to require that any verbal agreements be reduced to writing and filed. There were no exceptions made for contracts that related to existing service areas. In fact, the requirement that the Company obtain prior approval to vary from the uniform connection fees applied to both existing and new service areas, with a note that the filing of contracts that provided for non-uniform fees did not constitute Commission approval of such fees. Therefore, under the requirements set forth in Sub 111, the Carlson and Windward Cove agreements, which waived the uniform fees, should have been filed with the Commission to obtain prior approval for the non-uniform fees. The contracts themselves acknowledge this requirement, since they state that the fees are waived subject to the approval of the Commission. The Company clearly understands this, since Company witness Lubertozzi testified, "CWS is required to obtain permission for charging connection fees other than the uniform connection fee and list these deviations in its tariff. Otherwise, the uniform connection fee should apply. This was thoroughly discussed in Sub 118."

Since the Company failed to obtain prior approval to waive its uniform connection fees, the next issue is whether the uniform fees should be imputed. The Company's collection of connection fees, which vary from the amounts on its tariff, has been an issue in past rate cases, culminating with the Sub 118 tap fee investigation. In the Sub 118 case, the Public Staff proposed the imputation of connection fees because CWS charged connection fees based on the terms of its contracts as opposed to the approved fees listed on its tariff. The Commission disallowed the imputation of the unauthorized connection fees that were charged, because the Public Staff and the Attorney General had been aware of this practice in prior proceedings but had not proposed a ratemaking adjustment. The Commission determined that, because of the Public Staff's prior inaction, it had essentially waived its right to impute connection fees for ratemaking purposes with regard to any prior failure by CWS to seek and gain approval of contractually set connection fees. The Commission, however, went on to firmly state the following:

> Notwithstanding the many harsh admonitions and reprimands the Commission has delivered over the years to CWS regarding its connection fee practices and procedures, there is no reasonable basis, legal or equitable, upon which to adopt the ratemaking adjustment through the imputation of connection fees proposed in this case by the Public Staff and Attorney General. The time has come to bring this longstanding saga to an end. All parties, including CWS, the Public Staff, the Attorney General, and the Commission, share responsibility for failing to pursue these connection fee issues to a timely and reasonable conclusion. That being the case, CWS will be required, once and for all, to conform its tariffs on a subdivision-by-subdivision basis to reflect the connection fees actually being charged by the Company and future deviations will not be tolerated, but no imputation of connection fees will be ordered in this case.

84 Report of the NCUC Orders and Decisions 632, 653 (1994).

The Sub 118 order also made it clear that contracts or agreements were to be filed with the Commission and that any fees that varied from the uniform fees had to be approved by the Commission. Specifically, the Sub 118 order stated:

> That CWS shall file and request approval of all future contracts with developers within 30 days of signing said contracts, and in the case of informal agreements or contracts that are effective without signing, CWS shall file a written description of the terms of those agreements within 30 days of entering into such agreements. The requirements of this decretal paragraph shall apply to all future contracts, including those covering contiguous expansions. In all contracts that have provisions which allow for connection fees (tap-on fees) and/or plant impact fees that differ from the tariffed uniform connection charges and/or plant impact fees or that allow for special charges such as management fees, oversizing fees, availability fees or other such fees not common to all service areas, the referenced charges or fees shall be specifically brought to the attention of the Commission to be approved or disapproved.

Id. at 684.

Unfortunately, the Sub 118 order did not bring this longstanding saga to an end, as intended by the Commission. The Company continued to collect connection fees that varied from its uniform fees without receiving Commission approval to do so. Unlike the instances covered in the Sub 118 case, this is the first time that these variances from the uniform fees have been brought before the Commission, since the Company failed to file the agreements as required in Sub 111. The Company did have an opportunity to resolve the connection fees covered by the Carlson and Windward Cove agreements, but failed to disclose the fact that the connection fees had been waived for these areas in the filing required in the Sub 118 case. The Company claims that the Commission's Sub 128 order also placed the burden on the Public Staff to conform CWS's tariffs to the terms of arrangements, and that a copy of the Windward Cove agreement had been sent to Mr. Andy Lee of the Public Staff. First, the Sub 128 order only required that CWS and the Public Staff review the Schedule of Rates issued in that case and notify the Commission of any inconsistencies or errors by June 24, 1994. This order did not place on the Public Staff, instead of the Company, the burden of filing contracts with the Commission and obtaining Commission approval in order to vary from the uniform fees.

The Company appears to also assert that, instead of collecting a connection fee, as set forth in its tariff sheet, it can comply with its tariff by accepting plant in lieu of the connection fee. The Commission does not accept this argument. Connection fees, by definition, are to be paid in cash, and this is indicated on the tariff sheet when the amount of the fee is shown in dollars. The Commission has clearly stated in the Sub 118 order that any fees differing from the tariffed uniform connection fees were to be brought to the attention of the Commission to be approved or disapproved. Therefore, if the Company wished to not collect its uniform connection fee in an area in cash, for whatever reason, it should have applied to the Commission for approval to do so.

The Company was clearly warned in the Sub 118 case that no future deviations from its tariffed fees would be tolerated. It is the responsibility of the Company to comply with Commission orders and tariffs. Since the Company failed to do so, even after being warned that no future deviations would be tolerated, the Commission concludes that the authorized uniform connection fees of $1,100 per tap should be imputed in Mt. Carmel (Carlson agreement), Windward Cove, and Lamplighter Village South.

Furthermore, the Commission again reiterates that no future deviations from the Company's tariffed fees will be tolerated. Connection charges and plant modification fees are rates, and as such, require Commission approval. The Company should charge the authorized uniform connection charge and plant modification fee in all of its service areas, whether existing or new, unless it receives prior Commission approval to deviate from the uniform fees.

In the arrangement with Huber Construction regarding another project at the Mt. Carmel system, the Public Staff made an adjustment to impute $45 per tap. Public Staff witness Fernald testified that in a letter discussing the project, dated July 12, 1996, the Company states that it will collect a sewer connection fee of $1,805, of which it will remit $750 to MSD, resulting in a connection fee for CWS of $1,055, which is $45 less than the authorized uniform fee of $1,100. Public Staff witness Fernald further testified that the Company never filed an agreement for this project with the Commission, either as part of a contiguous extension filing or in response to the filing requirement established in Sub 118, nor did the Company request approval to vary from its uniform tap fee.

Company witness Weeks testified that in the Mt. Carmel system, CWS collects the wastewater through its collection facilities in Mt. Carmel and transports it to MSD for treatment and disposal. Witness Weeks further testified that the Company's collection of connection fees after remitting $750 to MSD compensates CWS in the form of CIAC, and that CWS's remittance to MSD serves as a substitute for CWS's need to own wastewater treatment and disposal facilities. Witness Weeks stated that in actuality CWS collected $1,805, more than the uniform fee, and that witness Fernald simply misstates the substance of the transaction in order to increase CIAC and reduce rate base.

On this issue, the parties disagree as to the substance of the transaction. It is the Public Staff's position that the Company is collecting connection fees on behalf of MSD, and therefore, the $1,805 fee collected consists of a $750 connection fee for MSD, and a $1,055 connection fee for CWS, which is $45 less than the uniform fee. The Company appears to take the position that CWS is paying the connection fee to MSD as part of its costs to provide service, and it is collecting a tap fee of $1,805, which is $705 more than its authorized connection fee.

As previously discussed, the Company is required to obtain permission before charging connection fees other than the uniform connection fee. In this instance, the Company clearly varied from its authorized connection fees without obtaining Commission approval to do so. Under the Public Staff's position, the Company undercollected $45 per tap, and the issue is whether this difference should be imputed. Under the Company's position, the Company overcollected $705 per tap, and the issue is whether the overcollection should be refunded. So first, the Commission must determine the substance of the transactions involved.

The July 12, 1996, letter to Mr. Huber, which was identified as CWS Fernald Cross Exhibit No. 14, states that CWS will be responsible for sending the payment of $750 per connection to MSD. There is also a handwritten note on the letter indicating that $750 of the $1,805 was sent to MSD for connection fees, leaving $1,055 for CWS. Based on this letter, the Commission agrees with the Public Staff that CWS was collecting a connection fee on behalf of

MSD and that the connection fee collected for CWS in this instance was $1,055, resulting in an undercollection of $45 per tap. In this case, the Company should have collected its uniform tap fee, since it failed to receive prior Commission approval to do otherwise. Therefore, the Commission concludes that the undercollection of $45 per tap should be imputed.

Refund Gross-Up

On August 20, 1996, the Small Business Job Protection Act of 1996 was signed into law. Section 1613 of this act restored the CIAC provisions that were repealed by the Tax Reform Act of 1986 for water and sewer utilities, effective for amounts received after June 12, 1996. On August 27, 1996, the Commission issued an order in Docket No. M-100, Sub 113, in which it ordered:

1. That all water and sewer companies cease collecting gross-up on collections of CIAC received after June 12, 1996.

2. That all water and sewer companies which have collected gross-up on CIAC received after June 12, 1996, refund any amounts collected to the contributors with 10% interest per annum within 30 days of the date of this order.

3. That all water and sewer companies who have collected gross-up on CIAC received after June 12, 1996, file a notarized report on the refunds made within 60 days of the date of this order. The notarized report should list the amount of gross-up collected on CIAC received after June 12, 1996, the interest on the refund and how it was calculated, and the total amount, including interest, which was refunded.

86 Report of NCUC Orders and Decisions, 1 (1996)

Public Staff witness Fernald testified that the Company failed to file the notarized report on refunds as required. Witness Fernald also testified that the Company failed to cease collecting gross-up as of June 12, 1996, in the Cambridge, Windsor Chase, Southwoods, Lamplighter Village South, Winghurst, and Matthews Commons systems. Witness Fernald recommended that the Company immediately cease collecting gross-up on CIAC and that the Company refund all gross-up collected on CIAC since June 12, 1996, to the current property owners, with 10% interest compounded annually. Witness Fernald also recommended that the gross-up collected in systems that have since been sold to an entity exempt from regulation by the Commission be treated as cost-free capital in this case.

Company witness Weeks testified that the Company determined that no report was due since it had stopped collecting gross-up on June 12, 1996. Witness Weeks also opposed making refunds as recommended by the Public Staff. Witness Weeks testified that the contracts for Cambridge, Southwoods, and Matthews Commons did not break down the connection fees into components, so that no portion of the fees were expressly earmarked as reimbursement for income taxes. Witness Weeks further stated that the developer was willing to enter into the transaction on the basis of the financial terms agreed to and never expected to obtain a refund if the tax laws changed in the future. Furthermore, witness Weeks testified that whoever bought the houses paid what they felt to be a fair price in light of market conditions. For the Windsor Chase and Winghurst systems, witness Weeks testified that the Company did collect grossed-up fees after June 12, 1996, but should be allowed to retain the gross-up as cost-free capital and a reduction to rate base. As to the Lamplighter Village South system, witness Weeks testified that, by the time the contract was executed, the Small Business Job Protection Act of 1996 had repealed the provision making CIAC taxable as ordinary income, and the contract makes no mention of gross-up. Witness Weeks also points out that the Commission approved this contract on May 19, 1998, and no mention was made at the time of the requirement that the contributor would pay any unauthorized gross-up. Finally, witness Weeks states that the Public Staff's recommendation that the refund be made to the current property owner contradicts the Commission's order in Docket No. M-100, Sub 113, which states that the refund is to go to the contributor.

The first area of disagreement between the parties concerns whether the Company failed to file the notarized report required by the August 27, 1996 order. As shown on the tap fee listing for 1996 filed with the Company's Form W-1, which was introduced as Public Staff Weeks' Cross-Examination Exhibit No. 1, the Company did refund gross-up collected after June 12, 1996, in most of its systems. Witness Weeks admitted to this during cross-examination. Therefore, since the Company refunded gross-up, it should have filed the notarized report on the refunds, as required by the Commission.

The next area of disagreement concerns whether the Company continued to collect gross-up after June 12, 1996, and if so, should the Company be required to refund the gross-up collected. The Commission has previously dealt with the issue of refunds of gross-up collected after June 12, 1996 in the Covington Cross case, Docket No. W-354, Sub 171. In its Order Denying Motion for Reconsideration issued on February 27, 2002, in that case, the Commission stated:

> In its Motion for Reconsideration, CWS seeks to remove the Commission from oversight of the connection fee transaction between contributor/customer and CWS. The connection fee is a tariff and it is regulated and established by the Commission. When the Tax Reform Act of 1986 (TRA-86) made utilities liable for paying taxes on CIAC, the Commission required (in an Order issued on August 26, 1987, in Docket No. M-100, Sub 113) the utilities to modify their tariffs to collect gross-up for taxes on CIAC from the contributor of the CIAC (whether it was a developer or a customer). The purpose of this requirement was to ensure that the contributor of the CIAC paid the taxes on the contribution and not the general customer base of the regulated utility. When the Small Business Job Protection Act (SBJPA) of 1996 restored the tax treatment of CIAC to its pre-TRA-86 status, the Commission issued an order (in Docket No. M-100, Sub 113, on August 27, 1996) requiring utilities to cease collecting gross-up for taxes on CIAC.
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> In its contract with the developer in this matter, the contractually agreed upon connection fee does not separate the connection fee amount into distinct amounts for a connection fee and gross-up for taxes on CIAC. However, the $1,795 connection fee is equal to the product of CWS's uniform connection fee of $1,100 multiplied by the Commission required gross-up multiplier. This contract was entered into during the period of time that CIAC was subject to taxation and it properly included provision for collecting gross up for taxes on CIAC. However,

> the notification of contiguous extension filed in this matter was filed after the Commission's Order to cease collecting gross up. Therefore, the inclusion of gross up for taxes on CIAC in this contract is in contravention of the Commission's Order. The Commission clearly can and must require CWS to cease collecting gross-up for taxes on CIAC and require the refund of any CIAC gross-up collected after the date of the SBJPA.

Order Denying Motion for Reconsideration, p. 5

As in the Covington Cross case, at the time the contracts for Cambridge, Southwoods, Matthews Commons, and Lamplighter Village South were entered into, CIAC was still subject to taxation and water and sewer utilities were required to collect gross-up. The fact that a contract does not specifically list the amount of gross-up does not mean that the Company did not comply with the gross-up requirement. For example, in its report on connection fees filed in Sub 118, the Company stated that the connection fees in the Cambridge contract included gross-up. The Commission's order issued on August 27, 1996 clearly states that water and sewer utilities are to cease collecting gross-up on CIAC, and the Company did not file exceptions or request clarification of this order. The Commission finds that the Company had no authority to continue collecting gross-up after June 12, 1996, and that the gross-up collected for systems still owned by the Company should be refunded. The Commission further concludes that the refunds should be made to the current property owners, consistent with the refunds required in North Topsail in Docket No. W-1000, Sub 5, and Covington Cross, Docket No. W-354, Sub 171. In the order issued on December 21, 2000, in Docket No. W-1000, Sub 5, which dealt with the issue of whether Utilities, Inc. should make refunds of overcollected gross-up on CIAC to contributors of the CIAC or to current property owners, Hearing Commissioner Ervin concluded that, "as between a developer and the initial purchaser, the developer is likely to have intended to sell the property to a purchaser, essentially acted as the agent of the purchaser in paying the tap fee, and undoubtedly intended to recoup the gross-up and tap fee in the price charged for the property. Similarly, as between homeowners, the tap fee represents payment for an integral part of the property, the cost of which has been undoubtedly passed on to each subsequent purchaser." The Commission concludes that the reasoning employed in its previous orders is applicable to the case at hand and should be utilized. CWS should make refunds of the gross-up that it overcollected to the current property owner whose name or names are listed on the deed to the property.

The Company also opposed refunding the gross-up at 10% interest compounded annually. Company witness Weeks testified that a lower interest rate would be appropriate, since it is unlikely that the contributor of the tap fee could have earned 10% on their investment. Witness Weeks further testified that since the Company is currently issuing customer deposit refunds at 8%, it would be proper to use this rate as the maximum rate for refunds of gross-up as well.

The Commission concludes that the appropriate interest rate on the refunds is 10%, compounded annually, consistent with the refund of gross-up in other cases. As discussed by the Commission in Docket No. E-7, Sub 501, since 1981, when G.S. 62-130(e) was enacted, the Commission has consistently used 10% to calculate interest on utility refunds. Since that time, interest rates have moved up and down. The Commission has used 10% notwithstanding the level of interest rates in the economy on the theory that 10% provides for adequate compensation over the long term considering the fact that a policy of tracking the general level of interest rates would lead to the denial of fair compensation in times when the interest rates exceed the statutory cap of 10%. In addition, the use of a 10% interest rate is also appropriate because the recipient of the return might have been able to avoid incurring higher cost debt, such as credit card debt, which typically involves an interest rate of more than 10%. Accordingly, the Commission is of the opinion that 10% continues to be a just and reasonable rate.

Based on the foregoing, the Commission concludes that the Company should (1) immediately cease collecting gross-up as required by the Commission's order issued on August 27, 1996, in Docket No. M-100, Sub 113, and (2) file, within 60 days of the effective date of this Order, a plan to refund the gross-up collected in the Cambridge, Windsor Chase water system, Southwoods sewer system, Lamplighter Village South, and Winghurst systems to the current property owners with 10% interest compounded annually.

The last issue is what should be done about the gross-up collected in the Windsor Chase sewer system, Southwoods water system, and Matthews Commons water and sewer systems, which have since been sold by the Company. Public Staff witness Fernald testified that, since it would be harder for the Company to make refunds in systems that they no longer own, she is recommending that the gross-up be treated as cost-free capital instead of requiring a refund. Witness Fernald further testified that the shareholders should not receive a windfall due to collecting gross-up when it had no authority to do so. Witness Fernald also stated on cross-examination that the gross-up collected was not CIAC, and should not be treated as such in the sale of the systems.

Company witness Weeks testified that regardless of what was collected for Windsor Chase and Matthew Commons, rate base should be zero, since the systems were sold. Witness Weeks also testified that the Public Staff's recommendation was inconsistent with the matching principle.

Gross-up was established to pay taxes related to CIAC, so that the net effect of the transaction to the utility should be zero. The collection of gross-up should not have any effect on the net investment in a system by a utility. Furthermore, the Company had no authority to collect gross-up after June 12, 1996. It is inappropriate to allow the Company's shareholders to retain these monies, when they were collected without authority, and are not part of the utility's net investment in the systems sold. The issue is whether these funds should be refunded or treated as cost-free capital. The Commission agrees with the Public Staff that, due to the difficulty in making the refunds since the Company no longer has customer records for these systems, the gross-up collected in these systems should be treated as cost-free capital in this and all future proceedings.

<u>Refund Bradford Park Overcollection</u>

Public Staff witness Fernald testified that the Company overcollected tap fees in the Stonehedge / Bradford Park systems and recommended that the overcollection be refunded to the current property owners with 10% interest compounded annually. The January 27, 1988 contract for the Stonehedge / Bradford Park systems stated that the combined water and sewer connection fee would be $2,300 per single family equivalent. Witness Fernald testified that at the time the contract was signed, water and sewer utilities were required to collect gross-up on CIAC, and in its report filed on November 30, 1992, in Sub 111, the Company indicated that the connection fees for Bradford Park were $441 for water operations and $971 for sewer operations, with the remaining balance of the $2,300 being gross-up. Witness Femald further noted that these connection fees of $441 and $971 are the amounts currently authorized for Bradford Park on the Company's tariff sheet.

Company witness Weeks opposed the Public Staff's recommendation, since the Company collected its contracted amount for this system. Witness Weeks testified that the Company ceased paying income taxes after 1996 and took the position that the way the contracts were written permitted CWS to retain and continue to collect the fees called for in the agreements. Witness Weeks also testified that the fact that the Public Staff and CWS disagreed does not mean that CWS disregarded the Commission's order to cease collecting gross-up. Finally, witness Weeks stated that any overcollection of tap fees benefits ratepayers by increasing CIAC and reducing rate base, thereby keeping rates low.

This is another instance where the Company continued to collect gross-up after June 12, 1996. The contract for this system was signed during the period that gross-up was required, and the amount of connection fees listed in the contract included gross-up, as stated by the Company in its November 30, 1992 report filed in Sub 111. Therefore, the Commission finds that the Company had no authority to continue collecting gross-up in Bradford Park after June 12, 1996, and that the gross-up collected should be refunded to the current property owners with 10% interest compounded annually. The Commission further concludes that (1) the Company should immediately begin charging its authorized connection fees in Bradford Park and (2) the Company should file, within 60 days of the effective date of this Order, a plan to refund the gross-up collected in Bradford Park to the current property owners, with 10% interest compounded annually.

<u>Reservation of Capacity Fees</u>

Public Staff witness Femald has included reservation of capacity fees that the Company collected in Rutledge Landing, Stewart's Crossing, Avensong, Brawley Farms, Canford Commons, and other areas in CIAC. Witness Femald testified that these fees were received from developers for plant costs and capacity and therefore, should be recorded as CIAC. Witness Femald also noted that in the orders recognizing the contiguous extensions for Rutledge Landing, Stewart's Crossing, Brawley Farms, and Canford Commons, the Commission ordered that the reservation of capacity fees be recorded as CIAC on the Company's books. Witness Femald testified that the Company did not record the reservation of capacity fees as CIAC as ordered by the Commission, but instead recorded 1/2 of the fee for Rutledge Landing on CWS Systems' books and recorded the fees for Stewart's Crossing and Brawley Farms as deferred credits on Utilities, Inc.'s books. Witness Femald also testified that the reservation of capacity fee for Avensong had been recorded as miscellaneous income on Utilities, Inc.'s books. Finally, witness Femald stated that the reservation of capacity fees should be included in CIAC in order to recognize the fact that the Company has the use of this money.

Company witness Weeks testified that, while the reservation of capacity fees should be treated as CIAC, there is an issue of matching and timing. Witness Weeks testified that if the reservation of capacity fees have not yet been used to fund the construction of backbone plant, it is appropriate to book the funds as a deferred credit and delay recognition of the funds as CIAC on the Company's books until the funds are used to purchase plant in service. Witness Weeks further testified that the reservation of capacity fees for Stewart's Crossing, Avensong, and Canford Commons should be included in CIAC since the systems are at build out and all customers have tapped on. On cross-examination, witness Weeks testified that the reservation of capacity fees should begin amortization in the year that the funds were used to purchase plant. Witness Weeks further testified that she began her amortization in the year the fees were collected, and stated that she did not know the year the funds were used.

The parties disagree on when reservation of capacity fees should be included in CIAC for ratemaking purposes. It is the Public Staff's position that these fees should be included in CIAC upon receipt, while the Company believes that the fees should not be included in CIAC until they are used to fund plant improvements. For Rutledge Landing, Brawley Farms, and other areas, the Company takes the position that the reservation of capacity fees should not be included as a reduction to rate base in this case, since the monies have not yet been used to purchase plant. These reservation of capacity fees have been collected from the developer and the utility has the use of this money until the money is used to fund plant additions. When the Company constructs the required plant expansions, such as expanding a wastewater treatment plant, the Company will accrue interest during construction of the plant to recognize the cost of the funds spent by the Company up to the time the project is completed and placed in service. At that time, the plant costs, including AFUDC, will be booked as an addition to plant in service. Just as the cost of money used during construction is recognized by including AFUDC in rate base, the fact that the Company has the use of the reservation of capacity fees should also be recognized, either as part of or in a calculation similar to AFUDC or by including the fees in CIAC upon receipt from the developer. Under the first option, the calculation of the interest on the fees would begin as soon as the reservation of capacity fees are received, and could continue for years, until the plant additions are constructed and placed in service. Due to this, recognizing the receipt of the reservation of capacity fees through this method is not a practical option. Instead, the Commission concludes that the reservation of capacity fees should be included in CIAC in this case, to recognize the fact that the Company has the use of the fees.

As for the Stewart's Crossing, Avensong and Canford Commons reservation of capacity fees, both parties agree that these fees should be included in CIAC in this case, and the only issue is when the fees should begin amortization. While it is the Company's position that the fees should begin amortization in the year the funds are spent on plant and included in CIAC, this is not how the Company actually calculated the amortization on its schedules. The Company did not know the year the funds were used to purchase plant, and began the amortization in the year the funds were received, which is inconsistent with the Company's own position, and results in the ratepayers never receiving the full benefit of the fees. The fact that the Company was unable to properly calculate the amortization illustrates the difficulty in keeping track of these fees and determining when specific fees are used to purchase plant. Since the Commission has found that reservation of capacity fees should be included in CIAC upon receipt, the amortization of the fees should begin in the year the fees are received.

Based on the foregoing, the Commission concludes that the appropriate level of reservation of capacity fees, net of amortization, to include in CIAC is $285,230, consisting of $136,764 for water operations and $148,466 for sewer operations.

<u>Management Fees</u>

The Public Staff made an adjustment to include in CIAC management fees that should have been collected since the last rate case, including management fees for 419 taps in the Cambridge subdivision and management fees for the Covington Cross system. The Public Staff also recommended that management fees that the Company overcollected in the Turtle Rock and Strathmoor systems be refunded to the current property owners with 10% interest compounded annually.

In her rebuttal testimony, Company witness Weeks agreed with the Public Staff's recommendation to refund the overcollections in Turtle Rock and Strathmoor, but proposed that the refund be made at an 8% interest rate. Witness Weeks opposed the Public Staff's adjustment to include the Cambridge management fees in CIAC. Although witness Weeks acknowledged that the Company did not collect management fees in Cambridge when they were authorized to do so, she stated that the Company's failure to do so was inadvertent. Witness Weeks further stated that, "of the many connection and management fees the Company collects each month, from time to time it will make mistakes." In the alternative, witness Weeks stated that if the Commission imputed the management fees, then the Company should be allowed to assess the current property owners for the fees. Finally, witness Weeks testified that the Covington Cross management fee of $100 per connection should be split between water and sewer operations, and since the water system is under CWS Systems, only one-half of the $100 fee should be included in CIAC in this case.

The first difference between the parties regarding management fees concerns the appropriate interest rate to be used in the calculation of refunds for the Turtle Rock and Strathmoor systems. As previously discussed under the refund of gross-up section, the Commission has found that 10% continues to be a fair and reasonable rate for utility refunds. Therefore, the Commission concludes that the Company should be required to refund the overcollection of management fees in the Turtle Rock and Strathmoor systems to the current property owners, with 10% interest compounded annually, and that the Company should file a refund plan within 60 days of the effective date of this order.

The next difference concerning management fees pertains to the fees for the Cambridge system. As previously discussed, it is the responsibility of management of the utility company to collect its authorized rates, including management fees. The Commission concludes that the Public Staff's adjustment to include the management fees that should have been collected in Cambridge in CIAC is appropriate. The Commission further concludes that the ratepayers should not be required to pay rates to allow a return on plant investment that should have been recovered through authorized management fee collections.

As to whether the Company should be allowed to assess the current property owners for these fees, as previously discussed, there is no statutory authority for assessing the customers for undercollections that were the result of the actions of the Company. Furthermore, the fees in question were for the years 1993 through 1999; the Company did not request an assessment until 2004, some five years later; and the Company should be estopped from now seeking and recovering an assessment. The Commission therefore concludes that the Company is not entitled to assess the current property owners in the Cambridge subdivision for management fees that it failed to charge.

Finally, the parties disagree on the level of fees to be included in CIAC for the Covington Cross system. The Public Staff calculated the management fees for the Covington Cross system based on a fee of $100 per lot, while the Company used both $50 and $100 per lot. In her rebuttal testimony, Company witness Weeks testified that the $100 management fee should be split between water and sewer operations, and since the water system is under CWS Systems, only one-half of the $100 fee should be included in CIAC in this case.

The management fee for the Covington Cross sewer system is set froth in the contract with the developer, which was filed in Docket No. W-354, Sub 171. This contract is just for the sewer system, and clearly states that the management fee is $100. On cross-examination, witness Weeks agreed that the $100 management fee should not be split between water and sewer operations. Therefore, the Commission concludes that the management fee for Covington Cross is $100 for sewer operations. Based on the $100 management fee, the management fees, net of amortization, to be included in CIAC for Covington Cross are $8,857, as recommended by the Public Staff.

Summary

Based on the foregoing, the Commission concludes that the appropriate amount of CIAC, net of amortization, is $18,536,122 for water operations and $15,416,949 for sewer operations.

ACCUMULATED DEFERRED INCOME TAXES

The parties disagree on the amount of ADIT to deduct from rate base in this proceeding. The Public Staff recommends an amount of $3,396,528 for water operations, which is $654,233 greater than the Company's proposed amount of $2,742,295. The Public Staff also recommends an amount of $2,033,281 for sewer operations, which is $380,873 more than the Company's proposed amount of $1,652,408. The differences in the level of ADIT recommended by the parties consist of the following items:

Item	Water	Sewer
ADIT - plant modification fees	$ 524,691	$ 302,814
ADIT - rate case expense	4,751	2,864
ADIT - deferred maintenance	(2,291)	(1,380)
ADIT - depreciation	127,082	76,575
Total	$ 654,233	$ 380,873

ADIT - Plant Modification Fees

Witness Fernald has removed from federal ADIT $670,712 and from state ADIT $156,793 associated with plant modification fees received by the Company in 2001, 2002, and 2003. CWS has included all cash payments received as tap fees as taxable income for tax purposes and has included a debit balance in ADIT associated with the receipt of plant modification fees. Witness Fernald testified that CWS collects plant modification fees for the expansion of and improvements for the utility system. Witness Fernald testified that the Public Staff had requested CWS's external auditors' opinion on the taxability of plant modification fees but has not received a response. Witness Fernald removed an amount of ADIT related to plant modification fees based on information available as of the date of her testimony because the Company had not provided the basis for taxing plant modification fees under the tax law changes.

CWS takes the position that plant modification fees are taxable income under the Job Protection Act of 1996. CWS has treated plant modification fees as taxable income and has actually paid tax on them. CWS has followed this procedure based on consultation with its tax experts, PriceWaterhouseCoopers.

On cross-examination, CWS asked witness Fernald to identify the authority she relied upon in support of her position that the post-2000 plant modification fees were not taxable. She identified the IRS final regulation issued on January 11, 2001. Witness Fernald cited portions of the regulation exempting Contributions in Aid of Construction from taxable income generally but listing as an exception customer connection fees.

In particular, witness Fernald cited Section (b)(1) on page 2255:

> (b) Contribution in aid of construction -- (1) In general. For purposes of Section 118(e) and this section, the term contribution in aid of construction means any amount of money or other property contributed to a regulated public utility that provides water or sewage disposal service to the extent that the purpose of the contribution is to provide for the expansion, improvement, or replacement of the utility's water or sewage disposal facilities.

Witness Fernald also cited Section (b)(3)(i) on page 2255. This portion of the regulation exempts from the definition of nontaxable CIAC customer connection fees:

> (3) Customer connection fee -- (i) In general. Except as provided in paragraph (b)(3)(ii) of this section, a customer connection fee is not a contribution in aid of construction under this paragraph (b) and generally is includible in income. The term customer connection fee includes any amount of money or other property transferred to the utility representing the cost of installing a connection or service line (including the cost of meters and piping) from the utility's main water or sewer lines to the line owned by the customer or potential customer. A customer connection fee also includes any amount paid as a service charge for starting or stopping service.

In support of its position that plant modification fees are taxable, CWS relies on other paragraphs of the same regulation. CWS relied upon paragraph (b)(4)(i):

> (4) Reimbursement for a facility previously placed in service -- (i) In general. If a water or sewage disposal facility is placed in service by the utility before an amount is contributed to the utility, the contribution is not a contribution in aid of construction under this paragraph (b) with respect to the cost of the facility unless, no later than 5½ months after the close of the taxable year in which the facility was placed in service, there is agreement, binding under local law, that the utility is to receive the amount as reimbursement for the cost of acquiring or constructing the facility.

CWS also cites Section (b)(5):

> (5) Classification of ratemaking authority. The fact that the applicable ratemaking authority classifies any money or other property received by a utility as a contribution is not conclusive as to its treatment under this paragraph (b).

In addition, CWS filed as a late filed exhibit a memorandum from PriceWaterhouseCoopers in which the firm stated that it agreed with CWS's tax treatment of plant modification fees. The Public Staff lodged no objection to Commission consideration of this late-filed exhibit. Specifically, Mr. Jerry Cahill stated that, for the 2001 through 2003 tax returns, "plant modification fees and tax/connection fees were properly included in taxable income on each tax return under the provisions of Internal Revenue Code Section 118 and Income Tax regulations thereunder." Finally, Public Staff witness Lucas testified on cross-examination that CWS serves in a number of subdivisions where the backbone facilities are in place before the residences in the subdivision are completely built out. Thereafter, infill occurs, and both tap fees and plant modification fees are assessed when new residences make connection to the water and sewer system. This testimony supports CWS's position that paragraph (b)(4)(i) is controlling. As a result the Commission concludes that CWS appropriately treated the plant modification fees as taxable income.

Based on the foregoing, the Commission concludes that CWS has appropriately accounted for such plant modification fees and that the appropriate amount of ADIT related to plant modification fees is $554,465 for water operations and $422,257 for sewer operations.

ADIT - Rate Case Expense

The Public Staff and the Company are recommending different amounts of ADIT related to rate case expense due to the differing levels of unamortized rate case expense. Based on its conclusions reached elsewhere in this Order regarding the appropriate level of unamortized rate case expense, the Commission concludes that the amount of ADIT related to rate case expense to deduct from rate base is $34,270 for water operations and $20,651 for sewer operations.

ADIT - Deferred Maintenance

The difference in the level of ADIT related to deferred maintenance is due to the different levels of deferred maintenance included by the parties in rate base. Based on the level of deferred maintenance costs to be included in rate base determined elsewhere in this Order, the Commission concludes that the amount of ADIT related to deferred maintenance to be deducted from rate base is $136,231 for water operations and $82,088 for sewer operations.

ADIT - Depreciation

The only difference between the parties in the calculation of ADIT - depreciation relates to the amount of pro forma plant additions to be included in the calculation. The Public Staff included the total amount of pro forma plant additions of $4,654,673 in its calculation, while the Company reduced the pro forma plant additions by the retirements of $1,057,221 before calculating depreciation.

The purpose of the calculation is to update ADIT to recognize the additional plant included in the rate case. The Company will be able to claim on its tax returns depreciation, including the 50% bonus depreciation, for the total amount of plant additions made, not just the amount net of retirements. Therefore, it is appropriate to calculate the adjustment to ADIT - depreciation based on the total pro forma plant additions.

Summary

Based on the foregoing, the Commission concludes that the appropriate amount of ADIT to deduct from rate base in this proceeding is $2,920,893 for water operations and $1,671,871 for sewer operations.

DEFERRED CHARGES

The Company and the Public Staff have recommended different levels of deferred charges as a result of maintenance expenses and rate case expense. As to the difference in deferred charges related to maintenance expenses, in her rebuttal testimony Company witness Weeks testified that Public Staff witness Henry omitted deferred charges of $13,294 from rate base. On cross-examination, witness Weeks stated that the $13,294 related to VOC testing. Public Staff witness Henry testified that he did not include VOC testing in deferred charges in rate base since the Commission has previously ruled that VOC tests are regular tests and should not be included in deferred charges.

In its final schedules filed on January 7, 2005, the Company increased the deferred charges for maintenance items from $403,546 to $575,791. In the final schedules filed by the Public Staff on January 12, 2005, the Public Staff increased its recommended level of deferred charges to $566,269, which is $9,522 less than the Company's final amount.

There is no testimony or evidence in the record explaining the difference between the parties' recommended levels of deferred charges for maintenance items. At the hearing, the difference between the parties' positions was due to VOC testing. The Commission has previously addressed the issue of deferred charges related to VOC testing in prior rate cases. In the last rate case, Docket No. W-354, Sub 128, the Commission found that an unamortized balance of VOC testing should not be included in deferred charges, since the Commission had not authorized specific cost recovery of VOC testing expenses but instead had included a normalized level of ongoing costs expenses.

Based on the note on Late Filed Exhibit KEW 3 indicating that the Company's amounts exclude VOC testing, it appears that the difference between the parties is no longer due to VOC testing. However, the Company has not provided any testimony or evidence that there are additional costs for which the Commission has authorized specific cost recovery, instead of including a normalized level in expenses. Since the Company has not provided any testimony or evidence supporting any additional deferred charges, the Commission concludes that the amount of unamortized deferred charges related to maintenance items recommended by the Public Staff is appropriate for use in this proceeding.

Elsewhere in this Order, the Commission has addressed the appropriate level of rate case expense to include in this proceeding and the amortization period for those rate case costs. Based on those conclusions, 2/3 of the rate case costs for this proceeding should be included in deferred charges.

Based on the foregoing, the Commission concludes that the appropriate level of deferred charges to include in rate base is $708,721, consisting of $482,129 for water operations and $226,592 for sewer operations.

COST-FREE CAPITAL

As previously discussed under CIAC, due to the difficulty in making the refunds since the Company no longer has customer records for the systems that have been sold, the gross-up collected in these systems should be treated as cost-free capital in this case.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of rate base for use in this proceeding is $30,372,584, of which $19,542,600 is applicable to water operations and $10,829,984 is applicable to sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52 - 60

The evidence supporting these findings is contained in the testimony of Public Staff witnesses Henry, Lucas and Fernald and Company witnesses Lubertozzi, Weeks and Daniel. The following tables summarize the amounts which the Company and the Public Staff contend are the proper levels of revenues to be used in this proceeding:

WATER OPERATIONS

Item	Company	Public Staff	Difference
Service revenues	$ 6,747,099	$ 6,896,512	$ 149,413
Miscellaneous revenues	133,966	208,366	74,400
Uncollectible accounts	(35,753)	(36,552)	(799)
Total operating revenues	$ 6,845,312	$ 7,068,326	$ 223,014

SEWER OPERATIONS

Item	Company	Public Staff	Difference
Service revenues	$ 5,340,312	$ 5,356,689	$ 16,377
Miscellaneous revenues	63,187	63,187	0
Uncollectible accounts	(27,770)	(27,855)	(85)
Total operating revenues	$ 5,375,729	$ 5,392,021	$ 16,292

As shown in the preceding tables, the Public Staff and the Company agree on the level of miscellaneous sewer revenues. Therefore, the Commission finds and concludes that the level agreed to by the parties for this item is appropriate for use in this proceeding.

SERVICE REVENUES

The parties disagree on the best way to determine water and sewer consumption. There is no dispute that the test year saw an unusually high rainfall. Public Staff witness Hinton testified that his statistical analysis showed that the 63.03 inches of rainfall, and the 139 days of rain observed during the 2003 test year in CWS's service area was abnormally high. He maintained that this unusually high rainfall contributed to a significantly lower number of gallons sold during the test year.

The parties generally agreed that an adjustment to the 2003 consumption amount was in order. Calculation of the appropriate adjustment was complicated by the fact that the Company was only able to provide consumption records for the years 1992, 1996, 2001, 2002, and 2003.

The Company recommended averaging the water consumption per REU for all five available years. However, the Public Staff recommended averaging the water consumption per REU only for the years 2001, 2002, and 2003, because, as acknowledged by Company witness Daniel, some of the Company's newer systems have appreciably higher water demand per connection as a result of such features as in-ground irrigation systems and because total water consumption increased every year from 1999 through 2002 before decreasing in 2003, as shown by the Company's Annual Reports.

On cross-examination, Public Staff witness Hinton acknowledged that the level of rainfall recorded in the Company's service area has ranged from a 30-year low in 2001 to a 30-year high in 2003. However, witness Hinton noted that the rainfall data averaged over the past three years, 45.49 inches, was close to the rainfall data averaged over the past thirty years, 44.67 inches, and that the three-year average of 112 days of rain is close to the 30-year average of 114 days. The rainfall data is presented in witness Hinton's Appendix A, page 9 of 12.

On the basis of the unusually heavy rainfall during the test year, the Commission is convinced that the test period level of water consumption should be adjusted. Because of the apparent increase in per customer usage over time, the consumption amounts for the years 1992 and 1996 are no longer representative and should not be used.

Based on the foregoing, the Commission concludes that the best method to determine water consumption is by averaging the water consumption per REU for 2001, 2002, and 2003, resulting in an average consumption of 5,300 gallons per month per REU, which is an 8.1% increase over the average consumption during 2003. Similarly, the best method to determine sewer consumption is by averaging the sewer consumption per metered REU for 2001, 2002, and 2003, resulting in an average consumption for sewer operations of 8,233 per month per metered sewer REU. Based on these average consumption amounts, the service revenues under existing rates are $6,896,512 for water operations and $5,356,689 for sewer operations.

MISCELLANEOUS WATER REVENUES

The parties disagree on the appropriate treatment of $74,400 of revenues from antenna space rentals. Public Staff witness Fernald testified that the Company recorded these revenues on Utilities, Inc.'s books, while recording the legal expenses associated with the leases on CWS's books. Witness Fernald further testified that, since the revenues are from the rental of elevated storage tanks, whose costs are being recovered from ratepayers, it is appropriate to flow the benefit of the lease payments to ratepayers, similar to the treatment of pole attachment revenue for electric companies.

Company witness Lubertozzi testified that the antenna lease revenues and legal fees should be recorded in nonutility income (Account 421) and miscellaneous nonutility expenses (Account 426), respectively, and should not be included in miscellaneous revenues in this case. Witness Lubertozzi further testified that property on which the antennas are connected belongs to the utility rather than the ratepayer and that the rates paid by the customers do not entitle them to any equitable interest in the Company's property. Witness Lubertozzi also testified that the Public Staff's position does not consider the fact that the assets on which the antennas are attached were contributed, and that the Company is not earning a return on the assets in question.

The Commission agrees with the Public Staff that the revenues from antenna space rentals are incidental revenues and should be included in miscellaneous revenues in this case. This treatment is consistent with the treatment of pole attachment revenues for electric companies, and with the treatment of antenna lease revenues for Heater Utilities, Inc. The Commission does not agree that the appropriate accounts for the leases are nonutility income and expense accounts, as stated by Company witness Lubertozzi. Under the Uniform System of Accounts (USoA) for Class A Water Utilities, which the Company should be following under Rule R7-35, revenues from antenna space rentals should be included in water operating revenues under Account 472 - Rents from Water Property. As stated in the USoA, this account shall include rents received for the use by others of land, buildings and other property devoted to water operations by the utility.

The fact that the elevated tanks to which the antennas are attached may have been contributed to the utility does not change the proper ratemaking and accounting treatment of these revenues. If the tanks were contributed, the shareholders have no investment in the property generating the revenues, and should not receive a windfall from the leases. Also, if the tanks were contributed, the developers who contributed the tanks recovered their costs through the sale of lots, so that, ultimately, the ratepayers have paid for the tanks. Finally, even though the Company proposes to include the revenues in nonutility income, the Company does not propose allocating any of the costs associated with the tanks, such as maintenance, property taxes, and deprecation expense, to nonutility operations.

UNCOLLECTIBLE ACCOUNTS

The difference between the Company and the Public Staff regarding uncollectible accounts results from the application of the uncollectible percentages to different levels of service and miscellaneous revenues recommended by the Company and the Public Staff. Having determined the appropriate level of service and miscellaneous revenues elsewhere in this Order, the Commission concludes that the appropriate level of uncollectible accounts is $36,552 for water operations and $27,855 for sewer operations.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of revenues under present rates for use in this proceeding is $12,460,347, of which $7,068,326 is applicable to water operations and $5,392,021 is applicable to sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 61

The evidence supporting this finding is contained in the testimony of Public Staff witness Lucas and Company witnesses Lubertozzi and Daniel and is not contested in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62 - 72

The evidence supporting these findings is contained in the testimony of Public Staff witnesses Henry, Lucas and Fernald and Company witnesses Lubertozzi, Weeks and Daniel. The following tables summarize the amounts that the Company and the Public Staff contend are the proper levels of maintenance expenses to be used in this proceeding:

WATER OPERATIONS

Item	Company	Public Staff	Difference
Salaries and wages	$ 1,373,215	$ 1,102,285	$ (270,930)
Purchased power	560,302	560,302	0
Purchased water	422,317	395,489	(26,828)
Maintenance and repairs	577,615	577,333	(282)
Maintenance testing	91,538	91,538	0
Meter reading	113,475	113,475	0
Chemicals	230,736	230,736	0
Transportation	126,026	126,026	0
Operating expenses charges to plant	(568,099)	(456,015)	112,084
Outside services – other	167,857	88,710	(79,147)
Total maintenance expenses	$ 3,094,982	$ 2,829,879	$ (265,103)

SEWER OPERATIONS

Item	Company	Public Staff	Difference
Salaries and wages	$ 827,448	$ 664,196	$ (163,252)
Purchased power	467,906	467,906	0
Purchased sewer	12,788	12,788	0
Maintenance and repairs	1,451,783	1,341,033	(110,750)
Maintenance testing	166,681	166,681	0
Meter reading	0	0	0
Chemicals	139,033	139,033	0
Transportation	75,939	75,939	0
Operating expenses charges to plant	(342,315)	(274,778)	67,537
Outside services – other	53,454	53,454	0
Total maintenance expenses	$ 2,852,717	$ 2,646,252	$ (206,465)

As shown in the preceding tables, the Public Staff and the Company agree on the levels of purchased power, purchased sewer, maintenance testing, meter reading, chemicals, transportation, and sewer outside services – other. 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

CWS has included in salary and wage expense costs for additional employees needed to comply with newly required daily chlorine testing. CWS witness Daniel explained the need for the new employees. N.C. Division of Environmental Health (DEH), pursuant to Rule #T15A: 18A. 1303(b), currently is requiring the daily chlorine residual monitoring (365 days/year) of chlorine residuals of all entry points and in the distribution system of water systems. Several of DEH's compliance inspection reports of CWS systems noted deficiencies for water systems not conducting daily chlorine checks.

Witness Daniel testified that CWS has evaluated the new DEH requirement to determine the most feasible and economical way of complying with this rule. Due to the significant number of CWS water systems and entry points spread across North Carolina, witness Daniel testified that CWS would require an additional 15 certified operators to conduct the daily chlorine residual tests of each entry point and in the water distribution system.

Witness Daniel testified that CWS had begun the hiring process for the 15 operators. CWS is advertising for additional operators throughout the state. CWS also has implemented an Employee Hiring Incentive Bonus Program rewarding existing employees who refer eligible applicants. If the referred applicant is hired and completes his or her probationary period, the referring employee receives an incentive bonus. Witness Daniel testified that the Public Staff and the Commission Staff both are aware of the new DEH requirement and the cost impact on the CWS customers and CWS as well as other water companies throughout the State.

The Commission determines that it should allow the costs CWS must incur to comply with the new regulatory requirements to be included in salaries and wages expense for rate-making purposes.. The new daily chlorine testing is a known and measurable change that was in place before the hearing in this case concluded. CWS has also, prior to the close of the case, begun to undertake the steps to comply with these new requirements. Compliance with the requirements is not optional. CWS must comply. These requirements are imposed on CWS by environmental regulators. Should the Commission refuse to allow recovery of these costs, CWS will be adding significant costs to fulfill its service responsibilities to its customers that will not be recovered through rates. This will result in immediate attrition and pressure to again increase rates.

The Commission concludes that salaries of $434,182 for fifteen new certified operators should be included in this case.

PURCHASED WATER

The parties disagree on the amount of purchased water expense. In its application for a rate increase, the Company applied an inflation adjustment to the cost of purchased water to recognize price increases. The Public Staff agreed that purchased water expense should be included in the inflation adjustment and made a similar adjustment in its prefiled testimony. At that point in time, the parties were in agreement on this issue. However, in his rebuttal testimony, Company witness Lubertozzi proposed an adjustment to purchased water expense to recognize increases in the rates charged by seven CWS providers. Witness Lubertozzi also applied the inflation adjustment to his adjusted level of purchased water expense, including the separate adjustment that he had already made to purchased water to recognize increases in prices. Finally, in the final exhibits filed by the Company on January 7, 2005, the Company revised the calculation of the inflation adjustment to exclude the adjustment that it had made to purchased water expense to reflect the increase in prices.

The disagreement between the parties concerns how price changes for purchased water should be recognized. This disagreement did not arise until the Company filed its rebuttal testimony, at which time it proposed a new adjustment to purchased water to recognize the increase in charges by its suppliers. Company witness Lubertozzi testified that, after reviewing the purchased water invoices, he determined that seven of the providers had increased either their base facility or usage charges. Witness Lubertozzi adjusted purchased water expense to recognize these price increases. Public Staff witness Lucas testified at the hearing that some of the items to which the inflation factor had been applied may have gone up by more than the 3.3% inflation factor and some may have gone up by less than 3.3%. Therefore, he recommended against pulling out a single item, such as purchased water and increasing it independently of the others. Witness Lucas also testified that he had not been able to review all of the Company's purchased water invoices for 2003.

The Commission agrees with the Public Staff on this issue. The Company has, in effect, made an adjustment to recognize price increases for purchased water twice, once through the inflation adjustment, and again by making a separate adjustment to purchased water expense for price increases. The Company appears to try to recognize this problem in its final schedules, but only removes the adjustment to purchased water from the inflation calculation, and not the total purchased water costs.

An inflation adjustment is made in order to recognize the overall increase in costs for a variety of expenses. Some of these expenses may not have changed since the test year. Some may have increased by less than the inflation adjustment, and some may have increased by more. Separating a portion of one expense from the many expenses adjusted for inflation is not appropriate. Therefore, the Commission concludes that the appropriate amount of purchased water expense is $395,489 before any annualization and inflation adjustments.

MAINTENANCE AND REPAIRS

The difference in the levels of maintenance and repairs recommended by the Company and the Public Staff is composed of the following:

Item	Water	Sewer
Deferred charges	$ (282)	$ (2,666)
Maintenance and repairs – sludge removal	0	(108,084)
Total	$ (282)	$(110,750)

Deferred Charges

The parties disagree on the level of amortization of deferred charges to include in expenses. In her rebuttal testimony, Company witness Weeks testified that $72 was missing from the Public Staff's recommended level of deferred expenses. Public Staff witness Henry testified at the hearing that the error of $72 relating to the amortization of deferred charges for water operations should be corrected. Based on the testimony of the parties at the hearing, it appeared that they were in agreement on the level of deferred expenses to be included in this case. However, when the Company filed its final schedules on January 7, 2005, it increased the level of deferred expenses from $151,992 to $197,924. In the final schedules filed by the Public Staff on January 12, 2005, the Public Staff increased deferred expenses to $194,976, which is $2,948 less than the Company's final amounts. The Company has not provided any testimony or evidence supporting the increase in deferred expenses. Since the Company has failed to provide evidence supporting any additional deferred expenses above the amount included by the Public Staff in its final schedules, the Commission concludes that the levels proposed by the Public Staff are appropriate for use in this proceeding.

Maintenance and Repairs - Sludge Removal

The parties disagree on the amount of sludge hauling expense, which covers all expenses related to sludge transport and disposal. Public Staff witness Lucas recommended a sludge hauling expense of $757,834, before the inflation adjustment. The Company recommended that the sludge hauling expense remain at the test year level of $865,918.

CWS relies on Bio-Tech, Inc., an affiliated company, to dispose of a substantial percentage of its sludge. Witness Lucas testified that CWS can accomplish its sludge transport and disposal for less expense than using Bio-Tech. Bio-Tech charges 4 to 5 cents per gallon to dispose of sludge from the CWS sewer plants in the Charlotte area. Witness Lucas testified that less expensive options exist in the Charlotte area. Witness Lucas testified that Bio-Tech charges 4 cents per gallon for sludge disposal. However, the Water and Sewer Authority of Cabarrus County charges 3 cents per gallon, and CMU charges 3.5 cents per gallon. According to witness Lucas, Bio-Tech charges 5 cents per gallon to transport sludge to the Bio-Tech disposal site near Columbia, South Carolina.

Witness Lucas calculated that Bio-Tech's total sludge transport and disposal cost during 2003 ranged from 7 to 10 cents per gallon for sewer plants in the Charlotte area. Witness Lucas calculated that an alternative provider CWS uses in the Charlotte area charges 6.75 cents per gallon for transport and disposal. For CWS's Old Point sewer plant in Pender County, Bio-Tech charges 10 cents per gallon, while the alternative provider charges 8.93 cents per gallon. Witness Lucas recommends that CWS always use the lowest cost option.

CWS witnesses Daniel and Lubertozzi testified in opposition to witness Lucas sludge hauling adjustment. They testified that CWS must look into aspects of sludge hauling services other than the bottom line costs. Reliability and quality also are important.

Witness Daniel testified that Bio-Tech has large sludge holding tanks and an application site that are designed to allow Bio-Tech to haul sludge 365 days per year; therefore, Bio-Tech's sludge hauling capabilities are much less affected by weather. Witness Daniel testified that smaller sludge hauling contractors do not have storage capabilities and haul with smaller tank trucks directly to their disposal sites where the sludge must be immediately applied.

Witness Daniel related instances where CWS had been denied service during rainy conditions because the application fields were too wet. He testified that the inability of these alternative providers to haul sludge lasted from one to several days. This placed the CWS plants in jeopardy of non-compliance. In contrast, Bio-Tech has never denied service.

Witness Daniel testified that Bio-Tech conducts a quality operation that protects CWS against potential liabilities and reduces CWS's operations expense by providing testing and reporting services other sludge hauling contractors do not provide. In particular, Bio-Tech provides toxicity character leaching procedure (TCLP) testing on a reoccurring basis. Other sludge hauling contractors require the utility to conduct this testing at its own expense.

Witness Daniel testified that Bio-Tech performs Microtox testing on every load of sludge transported to its facility to ensure that Bio-Tech limits CWS's liability. This testing insures that there is evidence that CWS's sludge is not hazardous to the environment. Most other sludge hauling contractors require the utility to be responsible for this liability.

Witness Daniel testified that small waste haulers who directly apply sludge to their fields require CWS to stabilize sludge to a 12 pH before it is hauled. Most sludge has a natural pH of 6.8 to 7.5.

CWS witness Lubertozzi testified that Bio-Tech provides a higher level of service and more services than some of the vendors identified by witness Lucas. Witness Lubertozzi testified that the Public Staff had failed to include in its analysis whether the "local" providers can accommodate the amount of sludge CWS produces. Witness Lubertozzi conducted his own analysis and concluded that the charges by the local providers as reported by witness Lucas were inconsistent with actual costs.

When witness Lubertozzi contacted the local providers listed by witness Lucas, some advised that they do not perform the testing services Bio-Tech provides. Others cannot haul sludge. Witness Lubertozzi testified that CWS would have to contract with a licensed waste hauler.

Witness Lubertozzi communicated with Bio-Nomic, Inc., which reported that it would charge CWS 3 cents to 4 cents per gallon to haul CWS's sludge. Contrary to what the Public Staff had reported, Bio-Nomic reported that it could not haul sludge for 2 cents per gallon because 2 cents per gallon would not cover the cost of fuel for the hauling truck.

Another local provider contacted by witness Lubertozzi reported that it did not wish to haul the CWS sludge or to undertake the responsibility or liability for accepting CWS's sludge. Other local providers stated that they too would be unwilling to accept the CWS sludge at the price stated by witness Lucas without more information on the percent to solid ratio, volume and frequency.

Based on information provided by witness Lucas, witness Lubertozzi calculated an average cost for all providers of $0.0923 per gallon, an average cost for providers excluding Bio-Tech of $0.0967, and a Bio-Tech cost per gallon of $0.0876. Witness Lubertozzi concluded from this analysis that the Public Staff analysis may be skewed by vendors willing to quote a lower price in an attempt to obtain new business. Witness Lubertozzi testified that price should not be the only consideration taken into account in determining whether sludge hauling costs should be recovered. Witness Lubertozzi testified that management's decision to hire Bio-Tech was a prudent one, and it is inappropriate to second guess this decision on the basis of hindsight as the Public Staff has done.

The Commission concludes that it should reject the Public Staff adjustment and include the full Bio-Tech test year costs in maintenance and repair cost. The Public Staff investigation has been one to identify the lowest possible cost combination of service without appropriate regard to other salient factors such as reliability and quality of service. It is inappropriate to disallow actual costs on the theory that for some sewage treatment plants a lower cost provider is available without obtaining assurances that the low-cost alternative provider can provide a comparable level of service. If for certain sewage treatment plants, CWS can save sludge hauling costs by using a local provider rather than Bio-Tech, but if CWS must incur additional costs for pH-balance or testing, the net impact may be no net financial benefit at all. The Public Staff has failed to include the additional costs in cost of service CWS would incur if it had not used Bio-Tech but other providers that did not test or balance the pH.

Based on the cross-examination it appears that CWS has more options in the Piedmont area than in the less populous areas of the State such as on the Eastern Seaboard. Obviously, CWS and its ratepayers benefit from the ability to have access to a readily available, reasonably priced sludge hauling provider that will not withhold its services for the difficult to serve routes.

Based on the foregoing, the Commission concludes that the appropriate amount for maintenance and repairs expense is $577,333 for water operations and $1,449,117 for sewer operations.

OPERATING EXPENSE CHARGED TO PLANT

The only difference in the parties' levels of operating expenses charged to plant relates to an adjustment made by the Company to increase maintenance salaries for fifteen additional operators. Both the Company and the Public Staff used the same methodology to calculate operating expenses charged to plant but disagree on the amount of maintenance salaries that should be used in the computation of an ongoing level of expense. Having determined the appropriate level of maintenance salaries elsewhere in this Order, the Commission concludes that the appropriate level of operating expenses charged to plant is $910,414, of which $568,099 is applicable for water operations and $342,315 is applicable to sewer operations.

WATER OUTSIDE SERVICES – OTHER

The only area of disagreement between CWS and the Public Staff concerning outside services for water operations is related to legal fees for Pine Knoll Shores (PKS) incurred from 1995 through 2002. The Public Staff removed these legal fees from plant in service and excluded them from test year expenses, while the Company also removed these legal fees from plant in service but amortized them to expenses over a seven-year period.

The Public Staff argues that the legal fees associated with CWS's PKS litigation are improperly listed under the category of organizational costs. The Public Staff believes that these expenses, incurred between 1995 and 2002, should be accounted for under the Other category. The Public Staff bases its proposition on the fact that the legal fees do not fit under the category of organizational costs as defined in the Uniform System of Accounts.[1] Further, he believes that the fees should not be recovered from the ratepayers as an expense because the utility's customers did not benefit from the lawsuit.

Although CWS agrees that the legal fees to do not fit neatly under the organizational costs category, it nevertheless feels the costs should be amortized. CWS further alleges that the Public Staff has made a determination without understanding the history of the litigation or the other issues addressed by the parties. Overall, CWS claims that the litigation was undertaken on behalf of its ratepayers and the ratepayer's interests were benefited.

The Commission, like the Public Staff and CWS, recognizes that the legal fees do not fit within the definition of category costs provided by the Uniform System of Accounts. However,

[1] According to the Public Staff, the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts (USOA) for Class A water utilties defines organizational costs as: all fees paid to federal or state governments for the privilege of incorporation and expenditures incident to organizing the corporation, partnership or other enterprise and putting it into readiness to do business.

the Commission does not entirely agree with both parties regarding the litigation costs. It is clear from CWS description of the history that both ratepayers and shareholders actually benefited to some degree from CWS' participation in this litigation. As CWS indicated in its proposed order, in 1995 the Town approached CWS about transferring the water system. When CWS refused, the Town began constructing a duplicate system paralleling CWS's lines. This led to a bevy of court proceedings in which it was finally decided that the restrictive covenants upon which CWS relied did not preclude the Town from building its system. The Town ultimately was unable to continue its efforts with the system.

The Commission believes, upon consideration of the entire record, that the legal expenses in question were actually incurred in the course of the Company's operations. In addition, the Commission believes that, while the legal expenses in question were primarily incurred for the benefit of the Company's stockholders, they also had potential benefits for the ratepayers for the reasons given by CWS. As a result, in the exercise of its discretion, the Commission concludes that one-half of the legal fees in question should be treated as an allowable operating expense and amortized to rates.

Based on the foregoing, the Commission concludes that the appropriate level of outside services - other for water operations is $128,284.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of maintenance expenses for use in this proceeding is $5,878,350, of which $3,028,299 is applicable to water operations and $2,850,051 is applicable to sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 73 - 83

The evidence supporting these findings is contained in the testimony of Public Staff witnesses Henry, Lucas and Fernald and Company witnesses Lubertozzi, Weeks and Daniel. The following tables summarize the amounts that the Company and the Public Staff contend are the proper levels of general expenses to be used in this proceeding:

WATER OPERATIONS

Item	Company	Public Staff	Difference
Salaries and wages	$ 431,734	$ 400,523	$ (31,211)
Office supplies & other office expense	203,702	203,702	0
Regulatory commission expense	46,004	26,083	(19,921)
Pension and other benefits	382,591	296,675	(85,916)
Rent	35,696	35,696	0
Insurance	202,068	202,068	0
Office utilities	100,749	100,749	0
Miscellaneous	45,235	45,235	0
WSC expense adjustment	(20,807)	(20,807)	0

Interest on customer deposits	14,768	14,768	0
Annualization adjustment	149,210	204,159	54,949
Inflation adjustment	84,930	83,302	(1,628)
Total general expenses	$ 1,675,880	$ 1,592,153	$ (83,727)

SEWER OPERATIONS

Item	Company	Public Staff	Difference
Salaries and wages	$ 260,147	$ 241,340	$ (18,807)
Office supplies & other office expense	122,744	122,744	0
Regulatory commission expense	27,720	15,716	(12,004)
Pension and other benefits	230,536	178,765	(51,771)
Rent	21,509	21,509	0
Insurance	121,759	121,759	0
Office utilities	60,708	60,708	0
Miscellaneous	23,849	23,849	0
WSC expense adjustment	(12,537)	(12,537)	0
Interest on customer deposits	8,899	8,899	0
Annualization adjustment	322,593	329,769	7,176
Inflation adjustment	93,184	88,061	(5,123)
Total general expenses	$ 1,281,111	$ 1,200,582	$ (80,529)

As shown in the preceding tables, the Public Staff and the Company agree on the levels of office supplies and other office expense, rent, insurance, office utilities, miscellaneous, WSC expense adjustment, and interest on customer deposits. 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 difference in the level of general salaries and wages recommended by the parties relates to the following items:

Item	Water	Sewer
Reclassification of operator	$ 3,109	$ 1,873
Project manager	(34,320)	(20,680)
Total	$(31,211)	$ (18,807)

The first area of difference between the parties pertains to reclassification of an operator hired after the end of the test year from general salaries to maintenance salaries. Both CWS and the Public Staff agree that this adjustment should be made but disagree on the amount that should be reclassified as maintenance salaries. Company Witness Weeks reclassified $11,440 of general salaries to maintenance salaries while the Public Staff only reclassified $6,458. The difference of $4,982 represents the amount that was allocated to other North Carolina companies by Public Staff witness Henry and not included in his prefiled exhibit as general salaries. Both parties are in agreement on the percentage of general salaries that should be allocated to other North Carolina companies.

CWS' calculation of general salaries in its revised rebuttal exhibits begins with the amount recommended by witness Henry in his prefiled exhibit, which did not include the $4,982 amount allocated to other North Carolina companies. Witness Weeks adjusted witness Henry's recommended general salaries to reclassify this new operator and consequently, removed more general salaries than was allocated to CWS. The Commission, therefore, concludes that $4,982 of salaries should be added back to general salaries in order to correct the Company's error.

The remaining difference between the Company and the Public Staff involves the salary of a project manager. CWS is attempting to fill a project manager position to meet increased regulatory requirements. At the time of his testimony, witness Daniel was reviewing resumes of those seeking the position. Witness Daniel testified that the duties of the project manager will include regulatory tracking and compliance, the preparation of Consumer Confidence Reports, Vulnerability Assessments, NPDES and PWS permit tracking and renewals, and annual reports. Also, this position will require the development of a system wide database and its continued update.

In addition, the project manager will be accountable for providing operational data as it pertains to the filing of contracts with the Commission. The project manager will ensure that all CIAC is consistent with Commission approved contracts, which will be accomplished by compiling and maintaining a data base of authorized connection, tap and management fees. The data base will be an essential tool to CWS and will be available to the Public Staff in future rate proceedings so as to alleviate some of the Public Staff concerns expressed in this case.

The Commission concludes that a project manager position is needed to meet increased regulatory requirements and that a salary of $55,000 for a project manager should be included in this case.

Based on the foregoing, the Commission concludes that the appropriate level of general salaries is $434,843 for water operations and $262,020 for sewer operations.

REGULATORY COMMISSION EXPENSE

The Company and the Public Staff differ on the appropriate amount of rate case expense in essentially two respects. The first involves an adjustment made by the Public Staff to reduce the hourly rate for Mr. Finley's legal fees to $250 per hour.

The Public Staff has adjusted the hourly rate attorney fee to reflect what it contends to be a reasonable fee level. The Public Staff has used a budgeted amount of approximately $13,000 for legal fees. The Public Staff notes that Mr. Finley's hourly rate is $380, a 52% increase from $250 hourly rate which he charged three years ago in the Total Environment Solutions, Inc. rate case, Docket No. W-1146, Sub 1. In the last general rate case for CWS, the Commission found that the $220 hourly rate charged by Mr. Finely for CWS was unreasonable and reduced legal fees recoverable in that case to reflect an hourly rate of $175. The Public Staff claims that the legal fee hourly amount is not reasonable and has recommended adjustments to $250 an hour.

CWS argues that the fees it pays are reasonable for a firm such as Hunton & Williams and is based on market conditions, years of experience, expertise and other factors. CWS further argues that the Public Staff has not done a sufficient analysis of the fee prior to acting to reduce it. Moreover, CWS argues that Public Staff has not made any adjustments to the actual costs incurred by the company other than attorney fees.

The Commission shares the Public Staff's concern regarding the issue of legal fees and believes that legal fees must be reasonable. However, the Commission does not agree with the Public Staff that $250 is a reasonable hourly attorney rate. In considering the time and date of the last rate case, the Commission finds that $300 an hour for legal services is a reasonable fee.

The second area of disagreement involves the Public Staff's use of a five-year amortization period for rate case expenses versus the Company's recommendation of a three-year period.

Public Staff witness Henry recommends that rate case expenses should be amortized over five years. He testified that seven years have passed since the Company filed a rate case in the Sub 165 proceeding. Prior to that, three years passed between the Sub 128 and Sub 165 rate case filings. Witness Henry testified that based on these recent rate case proceedings, CWS has on average filed for a rate increase every five years. Therefore, he testified, a five year amortization period for rate case costs would be more appropriate than the Company's three year amortization period.

CWS witness Lubertozzi testified in rebuttal. He testified that, based on a review of the Company's prior filings, the average period between the Company's rate case filings is three years. Witness Henry only used the last three cases.

The Commission concludes that it should amortize the costs over three years. A review of the Commission's official files indicates the following history of CWS rate cases: Docket No. W-354, Sub 16 (1981); Docket No. W-354, Sub 26 (1983); Docket No. W-354, Sub 39 (1985); Docket No. W-354, Sub 69 (1988); Docket No. W-354, Sub 91 (1989); Docket No. W-354, Sub 111 (1992); Docket No. W-354, Sub 128 (1994); Docket No. W-354, Sub 135 (1995) (withdrawn); Docket No. W-354, Sub 266 (2004). The average interval is approximately three years between cases. Historically, the Commission has used a three year amortization period. If the amortization period is too long, the costs of the case are not recovered from the ratepayers that were taking service during the test year and who imposed on the Company the increased costs requiring the request for a rate increase nor the ratepayers who will be taking service at the time the rates are adjusted, but by a future generation of ratepayers. The rate case amortization period should be accurately matched to be recovered from the ratepayers that will be taking service while the rates are in effect.

Based on the foregoing, the Commission determines an appropriate level of total rate case costs to be $213,678. Based on a three year amortization period, the annual level of regulatory commission expense to include in this proceeding is $71,226.

PENSION AND OTHER BENEFITS

The difference between the parties over pensions and other benefits arises from differences over salaries and wages. Based on resolution of those issues above, the Commission determines that the appropriate level of pensions and other benefits is $613,126, of which $382,591 is for water operations and $230,536 is for sewer operations.

ANNUALIZATION ADJUSTMENT

Both parties are in agreement on the methodology and expense categories to use in calculating an annualization adjustment. The parties disagree on the expense amounts for purchased water and maintenance and repairs that should be used to calculate an annualization adjustment. The Company and Public Staff also disagree on the water consumption factor to apply to the annualization expenses. Based on the Commission's findings elsewhere in this Order regarding purchased water and maintenance and repairs and the appropriate annualization and consumption percentages, the Commission concludes that the appropriate annualization adjustment is $204,159 for water operations and $348,792 for sewer operations.

INFLATION ADJUSTMENT

The Company and the Public Staff are in agreement on methodology and the inflation factor, but disagree on the level of expenses to which the factor should be applied. Specifically, the parties disagree on the expense amounts for purchased water, maintenance and repairs, and outside services - other that should be used to calculate an inflation adjustment. Based on the Commission's findings reached elsewhere in this Order regarding purchased water, maintenance and repairs and outside services - other, the Commission concludes that the appropriate inflation adjustment is $83,302 for water operations and $92,255 for sewer operations.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of general expenses for use in this proceeding is $3,038,065, of which $1,730,751 is applicable to water operations, and $1,307,315 is applicable to sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 84 - 88

The evidence supporting these findings is contained in the testimony of Public Staff witnesses Henry, Lucas and Fernald, and Company witnesses Lubertozzi, Weeks and Daniel. The following tables summarize the amounts that the Company and the Public Staff contend are the proper levels of depreciation and taxes to be used in this proceeding:

WATER OPERATIONS

Item	Company	Public Staff	Difference
Depreciation net of PAA & CIAC	$ 733,357	$ 731,150	$ (2,207)
Amortization of ITC	(311)	(311)	0
Taxes other than income	8	8	0
Property taxes	95,614	95,614	0

Payroll taxes	139,148	116,438	(22,710)
Regulatory fee	8,482	8,482	0
Gross receipts tax	282,733	282,733	0
State income tax	59,659	42,310	(17,349)
Federal income tax	273,688	194,100	(79,588)
Total depreciation and taxes	$ 1,592,378	$ 1,470,524	$ (121,854)

SEWER OPERATIONS

Item	Company	Public Staff	Difference
Depreciation net of PAA & CIAC	$ 379,387	$ 378,243	$ (1,144)
Amortization of ITC	(208)	(208)	0
Taxes other than income	5	5	0
Property taxes	57,613	57,613	0
Payroll taxes	69,986	70,162	176
Regulatory fee	6,470	6,470	0
Gross receipts tax	323,521	323,521	0
State income tax	32,856	18,728	(14,128)
Federal income tax	150,729	85,914	(64,815)
Total depreciation and taxes	$ 1,020,359	$ 940,448	$ (79,911)

As shown in the preceding tables, the Public Staff and the Company agree on the levels of amortization of ITC, taxes other than income, property taxes, regulatory fee, and gross receipts tax. Therefore, the Commission finds and concludes that the levels agreed to by the parties for these items are appropriate for use in this proceeding.

DEPRECIATION NET OF PAA & ITC

The difference between CWS and the Public Staff regarding depreciation net of PAA and ITC results from the parties' disagreement over the levels of CIAC that should be deducted from plant in service in determining depreciable plant. Based on the conclusions concerning CIAC reached elsewhere in this Order, the Commission concludes that the amount of depreciation expense proposed by the Public Staff is reasonable and appropriate for use in this proceeding.

PAYROLL TAXES

The difference between the Company and the Public Staff regarding payroll taxes results from the parties' disagreement over the appropriate level of salaries and wages to include in this proceeding. Having previously determined the appropriate level of salaries and wages for maintenance expenses and general expenses, the Commission concludes that the appropriate level of payroll taxes is $209,134, of which $139,148 is for water operations and $69,986 is for sewer operations.

STATE INCOME TAX

The Company and the Public Staff are recommending different levels of state income tax due to differing levels of revenues and expenses recommended by each party. Based upon conclusions reached elsewhere in this Order regarding the levels of revenues and expenses, the Commission finds and concludes that the appropriate levels of state income tax for use in this proceeding are $16,046 for water operations and $0 for sewer operations.

FEDERAL INCOME TAX

The Company and the Public Staff are recommending different levels of federal income tax due to differing levels of revenues and expenses recommended by each party. 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 federal income tax for use in this proceeding is $67,686 for water operations and $0 for sewer operations.

SUMMARY CONCLUSION

Based on the foregoing, the Commission finds and concludes that the appropriate level of depreciation and taxes for use in this proceeding is $2,176,186, of which $1,340,556 is applicable to water operations and $835,630 is applicable to sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 89 - 91

The evidence supporting these findings is contained in the Joint Partial Settlement Agreement filed by the parties on April 28, 2004.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 92

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 the Company's gross revenue requirements, incorporate the findings and conclusions found fair by the Commission in this Order.

SCHEDULE I

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
DOCKET NO. W-354, SUB 266
STATEMENT OF OPERATING INCOME AVAILABLE FOR RETURN
COMBINED OPERATIONS
For the Twelve Months Ended December 31, 2003, Updated to June 30, 2004

Item	Present Rates	Increase Approved	After Approved Increase
Operating revenues:			
Service revenues	$12,253,201	$2,174,614	14,427,815
Miscellaneous revenues	271,553	8,209	279,762
Uncollectible accounts	(64,407)	(11,433)	(75,840)
Total operating revenues	12,460,347	2,171,390	14,631,737

Operating revenue deductions:			
Maintenance expenses	5,878,350	0	5,878,350
General expenses	3,038,065	0	3,038,065
Depr. net of PAA & CIAC	1,109,393	0	1,109,393
Amortization of ITC	(519)	0	(519)
Taxes other than income	13	0	13
Property taxes	153,227	0	153,227
Payroll taxes	209,134	0	209,134
Regulatory fee	14,952	2,607	17,559
Gross receipts tax	606,254	105,057	711,311
State income tax	16,046	138,578	154,624
Federal income tax	67,686	641,659	709,345
Total oper. revenue deductions	11,092,601	887,901	11,980,502
Net operating income for return	$ 1,367,746	$1,283,489	$ 2,651,235

SCHEDULE II

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
DOCKET NO. W-354, SUB 266
STATEMENT OF RATE BASE AND RATE OF RETURN
COMBINED OPERATIONS
For the Twelve Months Ended December 31, 2003, Updated to June 30, 2004

Item	Amount
Plant in service	$ 82,973,405
Accumulated depreciation	(13,898,212)
Cash working capital	848,514
Contributions in aid of construction	(33,953,071)
Advances in aid of construction	(44,780)
Accumulated deferred income taxes	(4,592,764)
Customer deposits	(392,487)
Gain on sale and flow back of taxes	(289,628)
Plant acquisition adjustment	(1,880,811)
Water Service Corporation	256,584
Pro forma plant	3,597,452
Deferred charges	708,721
Excess capacity	(122,896)
Excess book value	(2,296,948)
Cost-free capital	(104,308)
Allocation of CWS office plant cost	(436,187)
Rate base	$ 30,372,584
Rates of Return:	
Present	4.50%
Approved	8.73%

SCHEDULE III

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
DOCKET NO. W-354, SUB 266
STATEMENT OF CAPITALIZATION AND RELATED COSTS
COMBINED OPERATIONS
For the Twelve Months Ended December 31, 2003, Updated to June 30, 2004

Item	Ratio %	Original Cost Rate Base	Embedded Cost	Net Operating Income
Present Rates:				
Debt	57.63%	$17,503,720	7.28%	$ 1,274,271
Equity	42.37%	12,868,864	.73%	93,475
Total	100.00%	$30,372,584		$ 1,367,746
Approved Rates:				
Debt	57.63%	$17,503,720	7.28%	$ 1,274,271
Equity	42.37%	12,868,864	10.70%	1,376,964
Total	100.00%	$30,372,584		$ 2,651,235

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 93

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Fernald and Company witness Lubertozzi. Public Staff witness Fernald testified that she was concerned about how the Company determines what connection charges and plant modification fees to charge customers, since there have been instances when the Company did not collect fees in accordance with its tariff sheet. Witness Fernald stated that she had requested a copy of any lists, references, or other documents used by the Company, either at its Northbrook office or at the North Carolina offices, to determine the amount of fees to charge, but she had not received a response. Witness Fernald also testified that the list of connection charges and plant modification fees filed by the Company with its application did not reflect the tariff sheet or the actual fees being charged. Witness Fernald recommended that the Company prepare and file with its rebuttal testimony a complete and accurate list of all connection charges and plant modification fees for review by the Public Staff and Commission so that an accurate tariff sheet could be issued in this case.

Company witness Lubertozzi testified that the Company currently has a list of authorized connection charges and plant modification fees, that the list is currently being revised and updated, and that the revised and updated list would be provided when the review was completed.

The connection charges and plant modification fees currently approved by the Commission are set forth in the tariff sheets attached as Appendix A to this Order. As previously stated in this Order, no future deviations from the Company's tariffed fees will be tolerated. The

Commission concludes that the Company should carefully review the connection charges and plant modification fees set forth in these tariff sheets for accuracy and file any comments or proposed corrections within 30 days. If no comments or proposed corrections are filed within that period, the proposed list of connection charges and plant modification fees will be deemed approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 94

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Fernald, and Company witness Weeks. Public Staff witness Fernald recommended that the Company be responsible for installing all meters, and no longer accept meters from developers. Witness Fernald also recommended that the Company be authorized to charge a meter fee of $50 for 5/8 or 3/4 inch meters, and actual cost for meters greater than 5/8 or 3/4 inch for all metered water connections. Company witness Weeks agreed with the Public Staff's recommendations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 95

The evidence supporting this finding for unmetered systems is contained in the testimony of Public Staff witness Lucas. The Company did not contest this finding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 96 - 99

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Fernald, and Company witnesses Weeks and Lubertozzi. The Public Staff made the following accounting recommendations concerning the recording of CIAC on the Company's books:

(1) That the Company begin recording management fees as CIAC, not revenues,
(2) That the Company begin recording all monies received for main extensions or to offset plant costs as CIAC,
(3) That the Company begin recording all reservation of capacity fees as CIAC on CWS's books,
(4) That the Company make entries on its books to reflect the amount of CIAC found reasonable by the Commission in this case,
(5) That the Company establish separate subaccounts for each form of CIAC, such as connection charges, plant modification fees, meter fees, management fees, reservation of capacity fees, contributed property, etc., and
(6) That the Company begin making an entry at year-end to true up amortization of CIAC to reflect the actual amount of CIAC collected during the year.

Company witness Weeks agreed that the management fees and payments for main extensions should be included in CIAC. Therefore, the Commission concludes that the Company should begin recording management fees and payments for main extensions or to offset plant costs as CIAC on its books. Company witness Weeks disagreed with the Public Staff's position that reservation of capacity fees should be recorded as CIAC on the Company's books. Elsewhere in this Order the Commission has found that reservation of capacity fees are

CIAC and should be treated as such in this case. Therefore, the Commission concludes that the Company should begin recording reservation of capacity fees as CIAC on CWS's books.

Company witness Lubertozzi testified that the Company would reflect the adjustments made to CIAC in this case on its books and records. Therefore, the Commission concludes that the Company should make entries on its books to reflect the amount of CIAC found reasonable in this case. As to establishing separate subaccounts for each type of CIAC, witness Lubertozzi testified that the "Company is currently reviewing the possibility of adding the additional accounts recommended by Staff and a recording mechanism to ensure accuracy." As noted under the discussion of CIAC, the Company receives several types of CIAC, including meter fees, management fees, and connection fees. The Commission believes that it would be useful to both the Company and the Commission and Public Staff if there were separate subaccounts for each type of CIAC received by the Company. Therefore, the Commission concludes that the Company should complete its evaluation of how separate subaccounts could be established and a recording mechanism to ensure accuracy could be erected, and file a report on its findings and recommendations with the Commission within 90 days of the effective date of this Order.

Finally, Company witness Lubertozzi opposed the Public Staff's recommendation that an entry be made on the Company's books to true up the amortization of CIAC at year-end. Witness Lubertozzi testified that the proposed recommendation will have no impact on the depreciation expense or amortization of CIAC on the utility's books and records, since any increase to amortization to CIAC would be offset by a corresponding increase to depreciation expense. Witness Lubertozzi also pointed out that the Public Staff made no recommendation to true-up utility plant in service at the end of the year, and that the Public Staff's recommendation would result in a mismatch of amortization and depreciation expense. Based on witness Lubertozzi's testimony, it appears that, along with including on its books an estimated amount for amortization of CIAC, the Company is also estimating the amount of depreciation expense that it records. Both depreciation expense and amortization of CIAC recorded on the Company's books should be calculated based on the actual amounts of plant and CIAC for that period. Therefore, the Commission concludes that the Company should make an entry on its books at year-end to reflect the actual amount of depreciation expense and amortization of CIAC for the year. The Commission further concludes that the Company should file with the Commission within 90 days of this Order a report detailing the changes the Company will make to its calculation of depreciation expense and amortization of CIAC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 100

The evidence for this finding of fact is found in the testimony of Public Staff witness Fernald and Company witnesses Lubertozzi and Weeks. Public Staff witness Fernald testified that the Company allocated pension and 401(k) costs to the various Utilities, Inc. subsidiaries by dividing the total cost by the total salaries, including part-time employees. The Company then applied this percentage to the full time employee salaries to determine the amount of pension and 401(k) costs for each Company, resulting in a mismatch between how the factor was calculated and how it was applied. Witness Fernald recommended that the Company correct its allocation of pension and 401(k) costs and begin calculating the percentage for pension and 401(k) costs based on salaries for full time employees.

Company witness Lubertozzi opposed the Public Staff's recommendation, stating that the recommendation was unduly burdensome to the Company, and that the mismatch that the Public Staff referred to is adjusted or corrected when the Company files a rate case. In its rebuttal testimony, the Company revised its calculation of pension and 401(k) costs to reflect the actual contribution percentages applied to the salaries for full time employees, instead of the allocation method used by the Company on its books.

The Commission concludes that, since the allocation of pension and 401(k) costs has been and will be corrected in rate cases, it is unnecessary to require the Company to revise its allocation of pension and 401(k) costs on its books.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 101

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Fernald and Company witness Lubertozzi. Public Staff witness Fernald recommended that the Company begin recording revenues from antenna space rentals in miscellaneous income on CWS's books. Company witness Lubertozzi testified that the revenues and associated legal fees should be recorded in nonutility income (Account 421) and miscellaneous nonutility expense (Account 426).

As discussed previously in this Order, under the USoA, revenues from antenna space rentals should be recorded in water operating revenues under Account 472 - Rents from Water Property.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 102

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Henry and Company witness Lubertozzi. Public Staff witness Henry testified that the Company does not take into account the plant modification fees received as an offset to plant costs in its AFUDC calculation. Witness Henry recommended that CWS evaluate how to appropriately account for the receipt of plant modification fees in its AFUDC calculation and file a revised policy.

Company witness Lubertozzi testified that the Company does not believe that an offset to the construction work in process used to accrue AFUDC is appropriate. Witness Lubertozzi stated that the plant modification fees represent less than 10% of the total capital expenditures for the Utilities, Inc. subsidiaries operating in North Carolina. Witness Lubertozzi also testified that reducing the basis used to calculate AFUDC by plant modification fees assumes that the cost rate of these funds is zero, and does not evaluate the opportunity costs that have been lost. In addition, witness Lubertozzi contended that a cost rate of zero or a reduction of CWIP would result in the Company paying customers interest on their plant modification fees as a reduction to rate base over the lives of the assets placed in service. Finally, witness Lubertozzi stated that the Company's current practice has been previously reviewed and approved by the Commission and Public Staff.

As previously discussed by the Commission, plant modification fees are collected by the Company to cover the cost of expanding and improving backbone facilities. When the Company constructs these backbone facilities, it calculates AFUDC to recognize the cost of the funds spent by the Company during construction of the plant. However, the Company fails to recognize the fact that, at the same time, it is receiving or has received plant modification fees to cover these costs, so a portion of the construction costs are funded through CIAC by plant modification fees, rather than by the Company. Based on the foregoing, the Commission concludes that the receipt of plant modification fees should be recognized in the calculation of AFUDC. Therefore, the Commission concludes that the Company should evaluate how to appropriately take into account the receipt of plant modification fees and file its revised AFUDC policy within 90 days of the effective date of this Order.

As to the Company's implication that the impact of plant modification fees on CIAC is immaterial, the Company's calculation has two flaws. First, the Company included all Utilities, Inc.'s North Carolina subsidiaries in its calculation, not just CWS, so it does not accurately reflect the impact of the plant modification fees on the calculation of AFUDC for CWS. Second, the Company divided the plant modification fees by total capital expenditures. The plant modification fees are to cover the cost of constructing backbone facilities, and it would be more appropriate to divide the plant modification fees by the annual cost of constructing new backbone facilities, not total capital expenditures, including replacements, vehicles, and all other plant additions.

One of the reasons witness Lubertozzi gave for not changing the AFUDC policy was that the current policy had been previously reviewed and approved by the Commission. However, witness Lubertozzi was unable to point to an order where the Commission approved the policy. Witness Lubertozzi did point to the recent rate case order for Transylvania Utilities, Inc. (TUI) in Docket No. W-1012, Sub 5 in support of his statement that the policy had been approved. The Company's AFUDC policy was not approved in that case. In fact, the stipulation in that case, which was filed on July 2, 2004, stated that "TUI agrees to evaluate how to appropriately take into account the tap fees received as an offset to plant costs in its AFUDC calculation. TUI shall file its revised AFUDC policy with the Commission within 60 days of the date that an order is issued in this case." Even if the policy has been previously approved by the Commission, that does not prevent the Commission from now recommending that the policy be changed on a go forward basis.

Finally, the Commission disagrees with the Company's contention that a zero cost rate or reduction in CWIP would result in the Company paying the customers interest on plant modification fees. The result of recognizing the receipt of plant modification fees is not to pay customers interest on the fees, but rather to prevent the Company from receiving in rate base interest on funds that were paid for by CIAC and not by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 103 - 104

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Lucas and Fernald and Company witness Lubertozzi. The Company has transactions with an affiliated company, Bio-Tech, including transporting and disposing of sludge. Public Staff witness Fernald testified that in Docket No. W-1012, Sub 5, Utilities, Inc. agreed in the stipulation with the Public Staff that it would reduce the affiliated transactions between Bio-Tech and its North Carolina regulated subsidiaries, which would include CWS, to writing, and file the contracts with the Commission within 90 days of the effective date of the order in that case, but that Utilities, Inc. had failed to do so. Witness Fernald recommended that the Company immediately file the affiliated contracts with Bio-Tech, as required in Docket No. W-1012, Sub 5.

Company witness Lubertozzi testified that the Company had reviewed its files but could not locate a copy of the Bio-Tech contract. Witness Lubertozzi stated that the Company was hesitant to draft a new contract until the original contract had been located, but if the original contract could not be located by the culmination of this rate case, the Company would draft, execute, and file a new contract with the Commission within 30 days of the final order in this case.

The Commission concludes that the Company should file the affiliated contract with Bio-Tech within 30 days of the effective date of this Order. The Commission further concludes that Utilities, Inc. should also file contracts covering the affiliated transactions between Bio-Tech and the North Carolina regulated companies other than CWS, as initially required in Docket No. W-1012, Sub 5, within 30 days of the effective date of this Order. The contract for each regulated company should be filed under the applicable docket number for that company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 105 - 107

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Fernald and Company witness Lubertozzi. Public Staff witness Fernald testified that the Company is not filing contracts with developers within 30 days as required by the Commission and that the Company is also serving customers in contiguous extensions without first posting a bond. Witness Fernald recommended that the Company file any contracts with developers not previously filed with the Commission within 90 days of the date of the order in this case. Witness Fernald also recommended that the Company evaluate its current practices and prepare a procedure that ensures that the Company complies with the rules and regulations of the Commission, in particular the filing of contiguous extensions and posting of bonds before serving customers. Witness Fernald recommended that the Company file its procedure with the Commission within 60 days of the date of the order in this case. Finally, witness Fernald stated that the Public Staff was willing to assist the Company with any questions on how to complete the forms or other matters, but ultimately, it is the Company's responsibility to comply with Commission rules and regulations.

Company witness Weeks testified that the Company did not intentionally neglect to file the contracts referenced in Public Staff witness Fernald's testimony. Witness Weeks requested that the Commission approve the contracts for Windward Cove, Mt. Carmel - Harmony, Hemby - Tyson Construction, Mt. Carmel - Huber Construction, Lamplighter Village South - Marshall, Bent Tree (sewer operations), and Mountainside at Wolf Laurel as part of this proceeding. Company witness Lubertozzi testified that, while the Company believes that it is current on all developer contracts, it is reviewing all files to determine if there are any other outstanding contracts. Witness Lubertozzi further testified that no other company is required to file contracts within 30 days of execution and, that the current Commission rules prevent service to customers before the contracts are addressed by the Commission. Witness Lubertozzi also testified that the Company had recently put procedures in place to ensure that all contracts are filed on a timely basis. Under these procedures, all executed contracts in North Carolina have a routing sheet to ensure that the employee responsible for filing the contract receives a copy. The Company also circulates a memo every two weeks advising all responsible departments of the status of the filing, what documents have been received from the developer, and what documents have been filed with the Commission. According to witness Lubertozzi, these follow up memos allow operations personnel to review all open dockets at the Commission pertaining to extensions, and any discrepancies are reported to the regulatory department and immediately corrected.

The Commission's orders in Docket No. W-354, Subs 111 and 118, which were issued in 1992 and 1994, respectively, required that the Company file contracts or agreements with developers within 30 days of the signing of the agreements. As noted by Public Staff witness Fernald and acknowledged by the Company, the Company has not complied with this filing requirement. On the contrary, it has failed to file certain contracts for approval, and for certain contracts that it has filed, the Company has failed to file them within the required 30 days. The Company has requested that the Commission approve the contracts that it had failed to file with the Commission as part of this proceeding, noting that the contracts had been provided to the Public Staff through discovery. However, these contracts have not been officially filed with the Chief Clerk of the Commission, and not all of these contracts have been filed as exhibits in this case. Therefore, the Commission concludes that the Company should be required to file any contracts with developers not previously filed with the Commission within 90 days of the effective date of this Order, including but not limited to the contracts for Southwoods/ Brandywine, Windward Cove, Mt. Carmel - Hemby, Mt. Carmel - Huber Construction, Lamplighter Village South - Marshall, and Bent Tree (sewer operations).

The next question is whether the Commission should continue to require the Company to file all contracts with developers within 30 days. The Commission acknowledges that no other water and sewer utility has a similar requirement; however, this requirement was established due to circumstances specific to this Company, and the concerns and issues that caused the requirement to be initially established still exist. Contracts relating to new service areas and contiguous extensions of existing service areas are now required to be filed by all water and sewer companies as part of the contiguous extension notification or franchise application. However, the requirement at issue here only requires the filing of the contract, not an entire application or notification within 30 days. Also, as a separate matter, under the Commission's current rules and regulations, a contiguous extension notification should be filed, and a bond posted, before the Company begins serving customers in the contiguous extension. Additionally, before the Company serves customers in a new service area, the Company should have applied for and received approval from the Commission for a certificate of public convenience and necessity in the new service area.

CWS is still not complying with the Commission's rules and regulations. The evidence presented during the hearing on this matter reveals that CWS is currently serving customers in contiguous extensions without having first posted a bond, and is serving customers in a new service area without first receiving a certificate of public convenience and necessity. Specifically, the Company began serving customers in the contiguous extensions in Reedy Creek Run in February 2003, Brookdale in July 2004, and Julian Meadows in May 2004. The Company also began serving customers, and charging rates, in the Larkhaven subdivision in February 2004. The Company has an application for a certificate of public convenience and necessity for Larkhaven pending before the Commission, but the Company failed to file a complete application, and, as a result, the Public Staff and Commission have been unable to process this filing.

In defense of the foregoing evidence, witness Lubertozzi testified that the Company has put into place procedures to ensure accuracy and completeness of filings before the Commission.

The Commission concludes that these procedures are not working, since the Company still has not filed all the outstanding exhibits and information for the pending cases where it is serving customers. Upon review of the Commission's files and records the Company has still not filed plan approval letters from the Department of Environment and Natural Resources (DENR), or other outstanding exhibits for the Larkhaven franchise, even though it is serving customers in that system.

Based upon the foregoing, the Commission is of the opinion that the requirement to file contracts within 30 days of signing should not be lifted until the Company has clearly shown that it has implemented procedures to ensure that it is complying with the rules concerning contiguous extensions and franchises, that those procedures are working, and that the Company is in compliance with Commission rules and regulations. Therefore, the Commission concludes that the Company should evaluate its current practices and prepare a new procedure that ensures that the Company will comply with the rules and regulations of the Commission, in particular the rules concerning contiguous extensions and franchises. The Company should file its procedure with the Commission within 60 days of the effective date of this Order. Finally, the Commission concludes that the Company should continue to file all contracts or agreements with developers in both existing and new service areas within 30 days from signing. These contracts or agreements should be filed with the Chief Clerk of the Commission. If any agreements are reached with developers regarding the provision of service but are not written or signed prior to being acted on, the Company should file with the Commission a detailed written description of the terms of the agreement within 30 days of entering into the agreement. The Commission will consider granting relief from this requirement upon approval of the procedures the Company has been required to file as described above.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 108

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Fernald and Company witnesses Lubertozzi and Weeks. Public Staff witness Fernald recommended that the Commission consider whether the Company's persistent failure to meet its legal obligations warrants penalties. The Commission's orders in Docket No. W-354, Subs 111 and 118, which were issued in 1992 and 1994, respectively, required that the Company file contracts or agreements with developers within 30 days of the signing of the agreements. The Public Staff has confirmed that CWS has not complied with this filing requirement, and has failed to file certain contracts for approval, and for the contracts that it has filed, the Company has failed to file them within the required 30 days.

System	Date of Agreement/Letter
Southwoods/Brandywine	11/09/93
Windward Cove	11/18/93
Mt. Carmel – Harmony	12/08/93
Hemby – Tyson Construction	02/29/96
Mt. Carmel – Huber Construction	07/12/96
Lamplighter South – Marshall	03/29/00
Bent Tree Sewer Operations	05/22/02
Mountainside at Wolf Laurel	06/10/03

The Public Staff has confirmed that CWS has not filed the above identified contracts which it has entered into with developers within the 30 days as required by the Commission. The Public Staff has learned that CWS is also serving customers in contiguous extensions without first posting a bond. Specifically, the Company began serving customers in the contiguous extensions in Reedy Creek Run in February 2003, Brookdale in July 2004, and Julian Meadows in May 2004. CWS also began serving customers, and charging rates, in the Larkhaven subdivision in February 2004.

According to the Public Staff, CWS has a history of noncompliance over many years, much of which remains uncorrected despite the Commission's instruction and warnings. The Public Staff argues that there are a significant number of detailed examples of the CWS's failure to comply with North Carolina law and the Commission's rules and regulations. The Public Staff believes this conduct should not be ignored.

CWS claims its omission to file the agreements was not intentional. CWS argues that there is compliance with the Commission's rules and regulations. CWS points out that no other company is required to file contracts within 30 days of execution and that current Commission rules prevent service to customers before the contracts are addressed by the Commission. CWS has recently put procedures in place to ensure that all contracts are filed on a timely basis. Under these procedures, all executed contracts in North Carolina have a routing sheet to ensure that the employee responsible for filing the contract receives a copy. CWS argues that its inaction does not rise to the level where the Commission should impose a fine or penalty. Moreover, CWS suggests that the imposition of a fine does not recognize the procedures that the Company has put in place to ensure that all contracts are filed with the Commission on a timely basis.

Based on the foregoing, the Commission agrees with CWS. The Commission does not take lightly CWS's failure to file its agreements and notices serving contiguous areas. However, the Commission views CWS's omission to comply with North Carolina law and the Commission's rules and regulations as unintentional. Without the necessary intent to defy the law and Commission's rules and regulations, the Commission is hesitant to levy any fine upon CWS.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company is hereby granted an increase in its water service revenues of $1,263,253 and sewer service revenues of $911,361.

2. That the Schedule of Rates, attached hereto as Appendix A, is approved for water and sewer utility service rendered by CWS on and after the date of this Order. This schedule is deemed filed with the Commission pursuant to G.S. 62-138.

3. That the Company should carefully review the connection charges and plant modification fees set forth in Appendix A and file any comments or proposed corrections within 30 days.

4. That a copy of the Notice to Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all customers along with the next billing.

5. That the Company shall charge the authorized uniform connection charge and plant modification fee in all of its service areas, whether existing or new, unless it receives prior Commission approval to deviate from the uniform fees.

6. That the Company shall file any contracts with developers not previously filed with the Commission within 90 days of the effective date of this Order.

7. That the Company shall continue to file all contracts or agreements with developers in both existing and new service areas within 30 days from signing. These contracts or agreements shall be filed with the Chief Clerk of the Commission. If any agreements are reached with developers regarding the provision of service but are not written or signed prior to being acted on, the Company shall file with the Commission a detailed written description of the terms of the agreement within 30 days of entering into the agreement.

8. That the Company shall evaluate its current practices and prepare a new procedure that ensures that the Company will comply with the rules and regulations of the Commission, in particular the rules concerning contiguous extensions and franchises. The Company shall file its procedure with the Commission within 60 days of the effective date of this Order.

9. That the Company shall immediately cease collecting gross-up as required by the Commission's order issued on August 27, 1996, in Docket No. M-100, Sub 113.

10. That the Company shall immediately begin charging its authorized connection fees in Bradford Park.

11. That the Company shall, within 60 days of the effective date of this Order, file a plan to refund the gross-up collected in the Cambridge, Windsor Chase water system, Southwoods sewer system, Lamplighter Village South, Winghurst and Bradford Park to the current property owners with 10% interest compounded annually.

12. That the Company shall file a plan to refund the overcollection of management fees in the Turtle Rock and Strathmoor systems to the current property owners, with 10% interest compounded annually, within 60 days of the effective date of this Order.

13. That the Company shall immediately begin recording management fees, payments for main extensions or to offset plant costs, and reservation of capacity fees as CIAC on its books.

14. That the Company shall make entries on its books to reflect the amount of CIAC found reasonable in this case.

15. That the Company shall complete its evaluation of how separate subaccounts for each type of CIAC could be established, and a recording mechanism to ensure accuracy, and file a report on its findings and recommendations with the Commission within 90 days of the effective date of this Order.

16. That the Company shall make an entry on its books at year-end to reflect the actual amount of depreciation expense and amortization of CIAC for the year. The Company

shall file with the Commission within 90 days of this Order a report detailing the changes the Company will make to its calculation of depreciation expense and amortization of CIAC.

17. That the Company shall immediately begin recording revenues from antenna space rentals in Account 472 - Rents from Water Property

18. That the Company shall evaluate how to recognize the receipt of plant modification fees in its AFUDC calculation and file its revised policy within 90 days of the effective date of this Order.

19. That the Company shall file the contract covering the affiliated transactions between Bio-Tech and CWS, including sludge hauling and other services, within 30 days of the effective date of this Order.

20. That Utilities, Inc. shall also file contracts covering the affiliated transactions between Bio-Tech and the North Carolina regulated companies other than CWS, as initially required in Docket No. W-1012, Sub 5, within 30 days of the effective date of this Order. The contract for each regulated company shall be filed under the applicable docket number for that company.

21. That the Company shall be responsible for installing all meters, and should no longer accept meters from developers. When meters are installed, the Company is authorized to charge a meter fee of $50 for 5/8 or 3/4 inch meters, and actual cost for meters greater than 5/8 or 3/4 inch, for all metered water connections.

22. The metering of unmetered water systems shall be accomplished as follows:

a. CWS shall solicit preliminary estimates from contractors, to be used as a basis for determining the approximate cost of installing meters;
b. This information shall be provided to each homeowners association in the unmetered areas within 90 days of the effective date of this Order;
c. If the homeowners association requests that meters be installed, CWS shall solicit bids within 60 days of the response from the homeowners association;
d. The homeowners association shall be allowed to review the final bid amount;
e. If the homeowners association approves the project based on the final bid amount, CWS shall award the contract within 30 days of final approval from the homeowners association and request approval from the Commission for an assessment to recover the cost; and

23. That CWS shall file with the Commission a status report regarding their progress on metering systems every six months after the effective date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of April, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

db041505.02

APPENDIX A

SCHEDULE OF RATES

for
CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA
for providing water and sewer utility service in
ALL ITS SERVICE AREAS IN NORTH CAROLINA

WATER RATES AND CHARGES

METERED SERVICE:
BASE FACILITIES CHARGES

A.	Residential Single Family Residence	$ 11.90
B.	Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 11.90
C.	Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (As in a Condominium Complex)	$ 10.90
D.	Commercial and Other (Based on Meter Size): 5/8" x 3/4" meter	$ 11.90
	1" meter	$ 29.75
	1-1/2" meter	$ 59.50
	2" meter	$ 95.20
	3" meter	$178.50
	4" meter	$297.50
	6" meter	$595.00

USAGE CHARGE:

A.	Treated Water/1,000 gallons	$ 3.60
B.	Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.40

FLAT RATE SERVICE:

A.	Single Family Residential	$ 25.60
B.	Commercial per single family equivalent (SFE)	$ 25.60

AVAILABILITY RATES (semi annual):
Applicable only to property owners in Carolina Forest and Woodrun Subdivision in Montgomery County — $ 14.40

METER TESTING FEE [1/]: — $ 20.00

NEW WATER CUSTOMER CHARGE: — $ 27.00

WATER AND SEWER – RATES

RECONNECTION CHARGES [2/]:

If water service is cut off by utility for good cause:	$ 27.00
If water service is disconnected at customer's request:	$ 27.00

MANAGEMENT FEE (in the following subdivisions only) :

Cambridge	$250.00
Southwoods/Brandywine at Mint Hill	$300.00
Windsor Chase	$ 63.00
Wolf Laurel	$150.00

OVERSIZING FEE (in the following subdivision only) :

Winghurst	$400.00

METER FEE:

For 5/8 or 3/4 inch meters	$ 50.00
For meters greater than 5/8 or 3/4 inch	Actual Cost

UNIFORM CONNECTION FEES [3/]:

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE	$100.00
Plant Modification Fee (PMF), per SFE	$400.00

The systems where connection fees other than the uniform fees have been approved by the North Carolina Utilities Commission are as follows:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Blue Mountain at Wolf Laurel	$ 925.00	$ 0.00
Britley	$ 0.00	$ 0.00
Buffalo Creek, Phase I, II, III IV	$ 825.00	0.00
Cambridge	$ 382.00	$ 0.00
Carolina Forest	$ 0.00	$ 0.00
Chapel Hills	$ 150.00	$400.00
Corolla Light	$ 500.00	$ 0.00
Eagle Crossing	$ 0.00	$ 0.00
Emerald Pointe/Rock Island	$ 0.00	$ 0.00
Forest Brook/Ole Lamp Place	$ 0.00	$ 0.00
Harbour	$ 75.00	$ 0.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Lemmond Acres	$ 0.00	$ 0.00
Monteray Shores	$ 500.00	$ 0.00

WATER AND SEWER – RATES

Subdivision	CC	PMF
Monteray Shores (Degabrielle Bldrs.)	$ 0.00	$ 0.00
Monterray	$ 0.00	$ 0.00
Quail Ridge	$ 750.00	$ 0.00
Queens Harbour/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Riverwood, Phase 6E (Johnston County)	$ 825.00	$ 0.00
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
Southwoods/Brandywine at Mint Hill	$ 0.00	$ 0.00
Stonehedge (Bradford Park)	$ 441.00	$ 0.00
Victoria Park	$ 344.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Williams Crossing	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$ 500.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

SEWER RATES AND CHARGES

METERED SERVICE: Commercial and Other

A. Base Facility Charge (Based on Meter Size)

5/8" x 3/4" meter	$ 11.70
1" meter	$ 29.25
1-1/2" meter	$ 58.50
2" meter	$ 93.60
3" meter	$ 175.50
4" meter	$ 292.50
6" meter	$ 585.00

B. Usage Charge/1,000 gallons (based on metered water usage) $ 5.30

C. Minimum Monthly Charge $ 35.50

D. Sewer customers who do not receive water service from the Company/SFE $ 35.50

FLAT RATE SERVICE: Per Dwelling Unit [4/] $ 35.50

COLLECTION SERVICE ONLY [5/]: (When sewage is collected by utility and transferred to another entity for treatment)

WATER AND SEWER – RATES

A.	Single Family Residence	$ 12.75
B.	Commercial/SFE	$ 12.75

MT CARMEL SUBDIVISION SERVICE AREA (based on metered water usage)

Monthly Base Facility Charge	$ 4.69
Usage Charge, per 1,000 gallons	$ 4.08

REGALWOOD AND WHITE OAK ESTATES SUBDIVISION SERVICE AREA

Monthly Flat Rate Sewer Service

Residential Service	$ 35.50
White Oak High School	$1,118.00
Child Castle Daycare	$ 143.00
Pantry	$ 78.00

NEW SEWER CUSTOMER CHARGE [6/]: $ 22.00

RECONNECTION CHARGE [7/]:

If sewer service is cut off by utility for good cause: Actual Cost

UNIFORM CONNECTION FEES [3/]:

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved by the North Carolina Utilities Commission are as follows:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amber Acres North (Phases II & IV)	$ 815.00	$ 0.00
Ashley Hills	$ 0.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Brandywine Bay	$ 100.00	$1,456.00
Cambridge	$ 841.00	$ 0.00
Camp Morehead by the Sea	$ 100.00	$1,456.00
Corolla Light	$ 700.00	$ 0.00
Emerald Pointe/Rock Island	$ 0.00	$ 0.00
Hammock Place	$ 100.00	$1,456.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Huntwick	$ 0.00	$ 0.00
Independent/Hemby Acres/ Beacon Hills (Griffin Bldrs.)	$ 0.00	$ 0.00

WATER AND SEWER – RATES

Subdivision	CC	PMF
Kings Grant	$ 0.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Kynwood	$ 0.00	$ 0.00
Monteray Shores	$ 700.00	$ 0.00
Monteray Shores (Degabrielle Bldrs)	$ 0.00	$ 0.00
Mt. Carmel/Section 5A	$ 500.00	$ 0.00
Queens Harbor/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Southwoods/Brandywine at Minthill	$ 0.00	$ 0.00
Southwoods, Phases 3A, 3B, and 4	$ 0.00	$ 0.00
Steeplechase (Spartabrook)	$ 0.00	$ 0.00
Stonehedge (Bradford Park)	$ 971.00	$ 0.00
Victoria Park	$ 756.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Williams Station	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston Pointe, Phase 1A	$2,000.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

MISCELLANEOUS UTILITY MATTERS

BILLS DUE:	On billing date
BILLS PAST DUE:	21 days after billing date
BILLING FREQUENCY:	Bills shall be rendered monthly in all service areas, except for Mt. Carmel which will be billed bi-monthly, and the availability charges in Carolina Forest and Woodrun Subdivisions which will be billed semi-annually.
FINANCE CHARGE FOR LATE PAYMENT:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.
CHARGES FOR PROCESSING NSF CHECKS:	$15.00

NOTES:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect a $20 service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

2/ Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

3/ These fees are only applicable one time, when the unit is initially connected to the system.

4/ Dwelling unit shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor building the unit.

5/ The utility shall charge for sewage treatment service provided by the other entity; the rate charged by the other entity will be billed to CWS' affected customers on a pro rata basis, without markup.

6/ These charges shall be waived if sewer customer is also a water customer within the same service area.

7/ The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 266, on this the 15th day of April, 2005.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-354, SUB 266
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that the North Carolina Utilities Commission has granted Carolina Water Service, Inc. of North Carolina (Applicant), an increase in its water and sewer rates in all of its service areas in North Carolina. The rates approved by the Commission are as follows and are effective for service rendered on and after the date of this Notice.

WATER RATES AND CHARGES

METERED SERVICE:

BASE FACILITIES CHARGES

A.	Residential Single Family Residence	$ 11.90
B.	Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 11.90
C.	Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (As in a Condominium Complex)	$ 10.90
D.	Commercial and Other (Based on Meter Size): 5/8" x 3/4" meter	$ 11.90

WATER AND SEWER – RATES

1" meter	$ 29.75
1-1/2" meter	$ 59.50
2" meter	$ 95.20
3" meter	$178.50
4" meter	$297.50
6" meter	$595.00

USAGE CHARGE:

A.	Treated Water/1,000 gallons	$ 3.60
B.	Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.40

FLAT RATE SERVICE:

A.	Single Family Residential	$ 25.60
B.	Commercial per single family equivalent (SFE)	$ 25.60

AVAILABILITY RATES (semi annual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivision in Montgomery County	$ 14.40
METER TESTING FEE [1/]:	$ 20.00
NEW WATER CUSTOMER CHARGE:	$ 27.00

RECONNECTION CHARGES [2/]:

If water service is cut off by utility for good cause:	$ 27.00
If water service is disconnected at customer's request:	$ 27.00

SEWER RATES AND CHARGES

METERED SERVICE: Commercial and Other

A.	Base Facility Charge (Based on Meter Size)	
	5/8" x 3/4" meter	$ 11.70
	1" meter	$ 29.25
	1-1/2" meter	$ 58.50
	2" meter	$ 93.60
	3" meter	$175.50
	4" meter	$292.50
	6" meter	$585.00
B.	Usage Charge/1,000 gallons (based on metered water usage)	$ 5.30
C.	Minimum Monthly Charge	$ 35.50
D.	Sewer customers who do not receive water service from the Company/SFE	$ 35.50

WATER AND SEWER – RATES

<u>FLAT RATE SERVICE</u>: Per Dwelling Unit [4/]	$ 35.50

<u>COLLECTION SERVICE ONLY</u> [5/]: (When sewage is collected by utility and transferred to another entity for treatment)

A.	Single Family Residence	$ 12.75
B.	Commercial/SFE	$ 12.75

<u>MT CARMEL SUBDIVISION SERVICE AREA</u> (based on metered water usage)

Monthly Base Facility Charge	$ 4.69
Usage Charge, per 1,000 gallons	$ 4.08

<u>REGALWOOD AND WHITE OAK ESTATES SUBDIVISION SERVICE AREA</u>

Monthly Flat Rate Sewer Service	
Residential Service	$ 35.50
White Oak High School	$1,118.00
Child Castle Daycare	$ 143.00
Pantry	$ 78.00

<u>NEW SEWER CUSTOMER CHARGE</u> [6/]:	$ 22.00

<u>RECONNECTION CHARGE</u> [7/]:

If sewer service is cut off by utility for good cause:	Actual Cost

ISSUED BY ORDER OF THE COMMISSION.
This the <u>15th</u> day of <u>April</u>, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. W-947, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Governors Club Development Corporation, 130 Edinburgh South, Suite 204, Cary, North Carolina 27511, for Authority to Increase Its Rates for Providing Sewer Utility Service in Governors Club Subdivision in Chatham County, North Carolina	)	ORDER APPROVING GRINDER PUMP INSTALLATION FEES

BY THE COMMISSION: On June 8, 2004, a Commission Hearing Examiner issued a Recommended Order Granting Partial Rate Increase concerning the application filed by Governors Club Development Corporation (GCDC) seeking authority to increase its rates for providing sewer utility service in Governors Club Subdivision in Chatham County, North Carolina. On June 23, 2004, the Governors Club Property Owners Association (GCPOA) filed exceptions to the Recommended Order.

On October 13, 2004, the Commission issued its Final Order Including Ruling on Exceptions. In said Order, in Finding of Fact No. 35, the Commission made the following finding:

> 35. It is appropriate to require the lot purchaser to be responsible for the initial purchase and installation of grinder pumps required for the system. Once the grinder pump is initially installed, it will be the responsibility of the utility to maintain, repair, and replace the grinder pump.

In the Evidence and Conclusions for Finding of Fact No. 35, the Commission observed that the installation fee for grinder pumps is very similar to the connection fee, whereby the customer has to pay a one-time fee to connect to the Company's system. The Commission stated that it understood that the customer has to purchase a grinder pump as well as pay for the installation of said pump, which then becomes the property of the utility, in order to obtain sewer utility service. The Commission explained that after the installation of a grinder pump, the utility becomes responsible for the maintenance, repairs, and the replacement of said pump. Accordingly, since such grinder pumps become the property of the sewer utility, the Commission concluded that a tariff should be created for the related installation.

Consequently, in the October 13, 2004 Order in Ordering Paragraph Nos. 7 and 8, the Commission ordered

> 7. That a grinder pump installation fee shall be included on the Schedule of Rates. The Company shall file no later than 30 days after the date of this Order its proposed grinder pump installation fee and a schedule of the underlying costs to be recovered.
>
> 8. That the Public Staff shall review the Company's proposed grinder pump installation fee as well as the related expenses incurred by the Applicant,

and shall file a report on the reasonableness of such proposal no later than 60 days after the date of this Order.

On November 12, 2004, GCDC filed its Application for Approval of Grinder Pump Installation Fee. GCDC applied for approval of a grinder pump installation fee for the S-18 Grinder Pump Station (2.5 horsepower (hp) grinder pump) in the amount of $3,770.01, and the M-50 Grinder Pump Station (5.0 hp grinder pump) in the amount of $8,556.18. GCDC explained that, due to the extreme elevation differences at Governors Club Subdivision and the various pressure heads against which the grinder pumps must pump, it is necessary for one of these two different types of grinder pumps to be installed depending upon the specific requirements of each lot.

On January 12, 2005, the Public Staff filed its report on the reasonableness of the Company's proposed grinder pump installation fees. The Public Staff agreed with the Company's installation costs for the S-18 Grinder Pump 2.5 hp and the M-50 Grinder Pump 5.0 hp, with the exception of the administration cost of $182.61 per installation which had been included by the Company. The Public Staff argued that the administration cost for siting, inventory, processing, and accounting associated with installing such grinder pumps was already included in contract accounting in this rate case. Further, the Public Staff opined that the administration cost associated with installing a grinder pump is a capital expense, and that GCDC should allocate this cost to plant in service. Accordingly, the Public Staff recommended that the appropriate installation fees should be: $3,587.40 for a S-18 Grinder Pump and $8,373.57 for a M-50 Grinder Pump. And the Public Staff recommended that in the future the cumulative administration costs for grinder pump installation should be allocated from contract salaries to plant in service.

On January 26, 2005, GCDC filed a statement with the Commission indicating that it had no comments on the Public Staff's report concerning grinder pump installation fees. However, GCDC requested that, as a cost saving measure, that it not be required to provide public notice of the Commission approval for the grinder pump installation fees to the customers since all existing sewer service customers already have grinder pumps installed and these customers would not be affected. Further, with respect to those persons that have purchased lots who have not yet built residences and are paying availability fees, GCDC stated that at or before their lot closing those persons received HUD property reports which contained estimates of the grinder pump installation costs. GCDC maintained that these lot owners are aware of the approximate costs to install grinder pumps; and, thus, GCDC requested that it not be required to provide notice of the Commission approval of grinder pump installation fees to its existing availability fee customers.

On January 27, 2005, the GCPOA, via e-mail transmittal to the Commission's General Counsel, notified the Commission that it was satisfied with the Public Staff's report concerning the grinder pump installation fees.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission finds good cause to approve the Public Staff's recommendations. GCDC is not contesting the Public Staff's recommendations; and the GCPOA informed the Commission that it was satisfied with the Public Staff's report. Accordingly, the Commission concludes that the appropriate grinder pump installation fees should be:

Grinder Pump Installation	Rate
S-18 Grinder Pump – 2.5 hp	$3,587.40
M-50 Grinder Pump – 5.0 hp	$8,373.57

The Commission also concludes that in the future the cumulative administration costs for grinder pump installation should be allocated from contract salaries to plant in service such that these administrative costs, which are a part of the grinder pump installation process, are capitalized, rather than expensed.

In addition, the Commission finds good cause to allow, as a cost-saving measure, GCDC's request that it should not now be required to provide notice of the Commission-approved grinder pump installation fee to its existing sewer service customers (630 customers at end of test year) and its availability fee customers (593 customers at end of test year). The existing sewer service customers will not be affected by these rates. The customers who have purchased lots, but who have not built houses and are paying availability fees have previously been provided with estimates of the grinder pump installation costs. Furthermore, in the Notice to Customers required by the October 13, 2004 Order, the narrative included in the Grinder Pump Installation Fee section of the Notice provided that the fee was to be established by further order and it indicated, in part, that the customer may either contract with the utility for installation at the Commission-established fee or obtain installation from a qualified third-party contractor. On November 15, 2004, the Company filed its Certificate of Service notifying the Commission that said Notice to Customers had been mailed or hand delivered to all affected customers. Thus, the availability fee customers were recently notified that they may contract with either the utility at the Commission to-be-established rate or, otherwise, may contract with a third-party contractor for the installation of their initial grinder pump.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of February, 2005.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

bk022105.01

Chair Jo Anne Sanford did not participate in this decision.

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Old Faithful Telcom Corp.; Teletrust, Inc., d/b/a	SC-1784, SUB 0	(10/25/2005)
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SmartStop, Inc. -- SC-1459, SUB 3; Order Reissu. Certif. Due to Address Change (09/15/2005)
T-Netix Telecomm. -- SC-756, SUB 4; Order Reissuing Certif. Due to Address Change (08/08/2005)
T-Netix, Inc. -- SC-942, SUB 4; Order Reissu. Certif. Due to Address Change (11/02/2005)
Value-Added Comm. -- SC-804, SUB 5; Order Reissuing Certif. Due to Address Chg. (10/20/2005)

SPECIAL CERTIFICATE/PSP - Name Change

MCI Comm. Serv. - SC-1325, SUB 2; Order Reissu. Certif. Due to Name Change (12/13/2005)

SMALL POWER PRODUCER

SMALL POWER PRODUCER – Certificate

Cliffside Mills, LLC - SP-147, SUB 0; Order Approving Transfer of Certificate (04/21/2005)
Fitzpatrick, Shawn - SP-153, SUB 0; Order Issuing Certificate (11/28/2005)
Hayden-Harman Foundation - SP-155, SUB 0; Order Issuing Certificate (12/21/2005)
Martin, Jeff & Bronwen - SP-146, SUB 0; Order Granting Certificate (01/27/2005)
Murphy-Brown, LLC - SP-151, SUB 0; Order Issuing Certificate (11/10/2005)
NC Solar Center - SP-145, SUB 0; Order Granting Certificate (01/27/2005)
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Catawba Valley Habitat for Hum. - SP-152, SUB 0; Order Approving Certificate (11/03/2005)
Witzgall; Chris & Gretchen - SP-142, SUB 0; Order Approving Certificate (04/18/2005)

SMALL POWER PRODUCER - Filings Due per Order or Rule

Westmoreland-LG&E Partners - SP-77, SUB 0; SP-77, SUB 2; SP-77, SUB 4; SP-77, SUB 5; Order Approv. Transf. of Certifs. Effect. with Transfer of Title (01/27/2005)

SMALL POWER PRODUCER - Sale/Transfer

Bullock Develop. Corp. - SP-139, SUB 1; SP-148, SUB 0; Order Approv. Transf. of Certificate Effective with Transfer of Title (03/16/2005)
Panda-Rosemary LP - SP-73, SUB 3; E-22, SUB 423; Order Approv. Transf. of Certif. & Generating Facility Subject to Conditions, Effective with Transfer of Title (02/03/2005)

TELECOMMUNICATIONS

TELECOMMUNICATIONS - Certificate

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Acceris Management & Acquisition LLC	P-1369, SUB 0	(08/09/2005)
Aero Communications, LLC	P-1393, SUB 0	(12/27/2005)
Asia Talk Telecom, Inc.	P-1385, SUB 0	(11/02/2005)
Balsam West Fibernet, LLC	P-1309, SUB 1	(03/15/2005)
Blue Diode Communications, LLC	P-1373, SUB 0	(08/17/2005)
CenturyTel Long Distance, LLC	P-1361, SUB 0	(04/26/2005)
CommPartners, LLC	P-1378, SUB 0	(11/02/2005)
Conterra Wireless Broadband, LLC	P-1359, SUB 0	(04/26/2005)
Cox North Carolina Telcom, LLC	P-1360, SUB 0	(06/17/2005)
CSP Telecom, Inc.	P-1371, SUB 0	(08/17/2005)
Dialtone & More, Inc.	P-1372, SUB 0	(09/02/2005)
DigitGlobal Communications, Inc.	P-1349, SUB 0	(01/24/2005)
Fiber Technologies Networks, LLC	P-1388, SUB 0	(12/08/2005)
Fonix Telecom, Inc.	P-1365, SUB 1	(07/08/2005)
FRC, LLC	P-1345, SUB 0	(08/12/2005)
Global Touch Telecom, Inc.	P-1387, SUB 0	(11/21/2005)
IBFA Acquisition Company, LLC	P-1362, SUB 0	(05/18/2005)
Industry Retail Group, Inc.	P-1328, SUB 1	(02/28/2005)
InfoNXX Carrier New York, Inc.	P-1356, SUB 0	(05/23/2005)
Infotelecom, LLC	P-1375, SUB 0	(08/17/2005)
Insite Solutions LLC, d/b/a Insite Fiber of North Carolina, LLC	P-1355, SUB 0	(04/06/2005)
IPC Network Services, Inc.	P-1383, SUB 0	(10/14/2005)
Kentucky Data Link, Inc.	P-1348, SUB 0	(01/07/2005)
Kentucky Data Link, Inc.	P-1348, SUB 1	(06/03/2005)
Matrix Telecom, Inc.	P-224, SUB 9	(08/01/2005)
Metrostat Communications, Inc.	P-1212, SUB 1	(06/14/2005)

NationsLine North Carolina, Inc.	P-1337, SUB 0	(01/24/2005)
Network PTS, Inc.	P-1350, SUB 0	(01/24/2005)
Network Service Billing, Inc.	P-1366, SUB 0	(07/08/2005)
NextG Networks of NY, Inc.	P-1338, SUB 0	(01/18/2005)
Nii Communications, Ltd.	P-1357, SUB 1	(04/06/2005)
NTC Communications, LLC	P-1351, SUB 0	(02/07/2005)
Pac-West Telecomm, Inc.	P-1002, SUB 2	(10/14/2005)
Pac-West Telecomm, Inc.	P-1002, SUB 3	(11/28/2005)
Phenix Communications, Inc.	P-1370, SUB 0	(07/20/2005)
RedSquare Corporation	P-1358, SUB 0	(05/25/2005)
RedSquare Corporation	P-1358, SUB 1	(05/25/2005)
Quality Telephone, Inc.	P-1367, SUB 0	(09/02/2005)
Quality Telephone, Inc.	P-1367, SUB 1	(08/08/2005)
Sprint Long Distance, Inc.	P-1377, SUB 0	(08/26/2005)
Sprint Long Distance, Inc.	P-1377, SUB 1	(12/06/2005)
StarVox Communications, Inc.	P-1379, SUB 0	(09/22/2005)
Sunesys, Inc.	P-1374, SUB 0	(11/09/2005)
Sunesys, Inc.	P-1374, SUB 1	(08/30/2005)
Tennessee Telephone Services, LLC	P-1324, SUB 0	(01/24/2005)
Teleconnect Long Distance Services & Systems Company	P-1382, SUB 0	(10/05/2005)
UCN, Inc.	P-1251, SUB 1	(07/01/2005)
United American Technology, Inc.	P-1376, SUB 0	(08/26/2005)
Vanco Direct USA, LLC	P-1364, SUB 0	(06/23/2005)
Vanco Direct USA, LLC	P-1364, SUB 1	(09/16/2005)
Vycera Communications, Inc.	P-1363, SUB 0	(05/18/2005)
Vycera Communications, Inc.	P-1363, SUB 1	(09/08/2005)
800 Response Information Services, LLC	P-1354, SUB 0	(03/11/2005)

Cox North Carolina Telcom -- P-1360, SUB 0; Order Reissu. Certif. to Correct Error (06/23/2005)
LecStar Telecom – P-914, SUB 3; Order Cancel. Provis. Auth. to Offer Prepaid Serv. (12/01/2005)
Mercury Long Distance -- P-1083, SUB 0; Order Dismiss. Applicat. & Closing Docket (08/09/2005)
NTC Comm. – P-1351, SUB 1; Recom. Order Grant. Cert. of Pub. Conven. & Necessity (07/06/2005)

TELECOMMUNICATIONS - Cancellation of Certificate

Certificates Canceled – Local & Long Distance

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American Farm Bureau	P-1041, SUB 2	(12/20/2005)
Bee Line Long Distance	P-1244, SUB 1	(01/07/2005)
Capsule Communications, Inc.	P-942, SUB 3	(04/06/2005)
Call Processing, Inc.	P-1048, SUB 1	(11/07/2005)
ECI Communications, Inc.	P-1162, SUB 1	(03/30/2005)
GE Business Productivity	P-1097, SUB 1	(08/22/2005)
	P-1339, SUB 0	
KMC Telecom III LLC	P-824, SUB 8	(08/17/2005)

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NII Communications, LTD	P-1357, SUB 2	(08/26/2005)
OneStar Long Distance, Inc.	P-355, SUB 10	(03/08/2005)
Telemanagement Services, Inc.	P-907, SUB 1	(04/07/2005)
TelMatch Telecommunications, Inc.	P-615, SUB 2	(12/08/2005)
Teleglobe America, Inc.	P-1283, SUB 1	(09/01/2005)
Teligent Services, Inc.	P-870, SUB 8	(02/07/2005)
Tralee Telephone Company	P-1199, SUB 1	(08/26/2005)
VIVO-NC, LLC	P-1073, SUB 2	(08/08/2005)

BellSouth L.D. -- P-654, SUB 5; P-691, SUB 1; Order Cancel. Certif. & Clos. Dockets (01/12/2005)
E-Z Tel -- P-656, SUB 7; Order Allow. Discontin. (10/04/2005); Order of Cancellation (10/17/2005)
GTC Telecom -- P-821, SUB 2; P-55, SUB 1596; Order Authoriz. Disconnect. With Due Notice & Promulgating Interim Rule (11/22/2005)
Phone-Link, Inc. -- P-897, SUB 1; Order Concerning Certificate Cancellation (07/11/2005)
XO North Carolina -- P-732, SUB 4; P-890, SUB 3; P-997, SUB 4; P-1325, SUB 0; Order Canceling Certificates and Closing Dockets (02/08/2005)

TELECOMMUNICATIONS - Complaint

BellSouth Telecommunications, Inc. -- P-55,
SUB 1536; Order Deny. Request to Reconsider Order Finding No Reasonable Grounds to Further Investig. Complaint (Edna J. Hayes) (03/23/2005)
SUB 1537; Order Dismissing Complaint and Closing Docket (Mike Martinelli) (12/19/2005)
SUB 1539; Order Dismissing Complaint and Closing Docket (Robert J. Bish) (01/13/2005)
SUB 1543; Order Dismiss. Complaint and Closing Docket (Jack & Sue Weston) (08/03/2005)
SUB 1548; Order Dismiss. Complaint & Closing Docket (AT&T) (03/30/2005)
SUB 1551; Order Dismiss. Complaint & Closing Docket (US LEC & SCCA) (04/12/2005)
SUB 1554; Order Dismiss. Compl. & Clos. Docket (Maggie Valley Ice Cream) (07/21/2005)
SUB 1557; Order Dismiss. Complaint & Clos. Docket (The Profit Group, Inc.) (07/12/2005)
BTI Telecom & ITC DeltaCom -- P-89, SUB 80; Order Dismiss. Complaint & Closing Docket (Bleecker Automotive Group) (01/14/2005)
Carolina Telephone & Telegraph -- P-7, SUB 1097; Order Dismiss. Complaint & Closing Docket (Minnie Louise McLaughlin) (05/31/2005)
Utilities Comm., New Smyrna Beach -- P-1292, SUB 2; Order Dismiss. Complaint & Closing Docket (Epicus, Inc.) (06/30/2005)
Verizon South -- P-19, SUB 496; Order Dismiss. Complaint & Closing Docket (T. Clark III, M.D.) (12/08/2005)
Yadkin Valley -- P-968, SUB 2; Order Dismiss. Complaint with Prejud. (ISP Alliance) (09/19/2005)

TELECOMMUNICATIONS - Contracts/Agreements
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SUB 135 (Madison River Comm.) (10/06/2005)
SUB 137 (Cricket Communications) (05/12/2005)
SUB 138 (Global Connection Inc. of NC) (05/12/2005)
SUB 139 (FLATEL, Inc.) (05/12/2005)
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BellSouth Telecommunications, Inc. – P-55,
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SUB 1338 (Unicom) (04/21/2005)
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SUB 1346 (DIECA, d/b/a COVAD) (11/28/2005)
SUB 1356 (Momentum Business) (04/07/2005)
SUB 1359 (Budget Phone) (04/07/2005)
SUB 1371 (Sprint Comm. Co. L.P.) (08/04/2005)
SUB 1372 (The Other Phone Co.) (04/07/2005); (04/21/2005)
SUB 1377 (Alternative Phone) (07/22/2005)
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SUB 1407 (Ready Telecom) (07/22/2005)
SUB 1410 (CAT Comm.) (07/22/2005); (08/11/2005)
SUB 1411 (Time Warner Telecom) (08/11/2005); (10/06/2005)
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SUB 1460 (Z-Tel Comm.) (04/07/2005); (04/21/2005); (10/28/2005)
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SUB 1503 (Global Connect. of America) (07/22/2005) (08/19/2005)
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SUB 1528 (Southern Digital Network) (07/22/2005)
SUB 1532 (ALLTEL Comm.) (08/11/2005); (08/11/2005)
SUB 1533 (ACCESS Integrated Networks) (10/28/2005)
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SUB 1544 (United States Cellular Corp.) (05/27/2005)
SUB 1547 (N.C. RSA 3 Cell. Telephone, d/b/a Carolina West Wireless) (05/12/2005)
SUB 1559 (Tennessee Telephone Serv., d/b/a Freedom Comm.) (08/04/2005)
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- SUB 1582 (Connect Communications) (10/28/2005)
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- SUB 1584 (Budget Phone, Inc.) (10/28/2005)
- SUB 1585 (Electronic Services Co.) (10/28/2005)
- SUB 1586 (Metropolitan Telecomm.) (11/28/2005)
- SUB 1587 (CAT Comm. International) (11/28/2005)
- SUB 1588 (BellSouth Long Distance) (11/28/2005)
- SUB 1589 (Time Warner Cable Infor. Serv. (N.C.) (11/28/2005)
- SUB 1590 (New Cingular Wireless PCS) (12/16/2005)
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- SUB 1594 (BalsamWest FiberNET) (12/16/2005)
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- SUB 1598 (Progress Telecom) (12/16/2005)
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- SUB 1600 (Fonix Telecom, Inc.) (12/16/2005)
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Carolina Telephone and Telegraph Company & Central Telephone Company
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- P-7, SUB 1096; P-10, SUB 727 (Simflex Communications) (01/06/2005)
- P-7, SUB 1098; P-10, SUB 728 (Vertex Communications) (01/28/2005)
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- P-7, SUB 1104; P-10, SUB 734 (TDPC, Inc.) (08/04/2005)
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Carolina Telephone and Telegraph Company & Central Telephone Company
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ITC^DeltaCom -- P-500, SUB 18 (BellSouth) (10/06/2005)

Lexcom Telephone Company – P-31, SUB 142 (Cricket Communications) (10/18/2005)

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SBC Telecom -- P-936, SUB 4; P-140, SUB 88; Order Approv. Transfer of Control (04/07/2005)
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Randolph Telephone Co. -- P-61, SUB 89; Order Approv. Price Reg. Plan (11/23/2005)

Sprint Comm. Co. -- P-294, SUB 28; Order Dismiss. Arbitration with Prejudice (07/27/2005)

SBC Long Distance, LLC. -- P-638, SUB 3; Order Grant. Numbering Resources (08/12/2005)

TCG of the Carolinas -- P-646, SUB 11; Order Granting Numbering Resources (06/17/2005)

Verizon South, Inc. - P-19,
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Xspedius Mgmt. Co. -- P-1202, SUB 6; Order Granting Numbering Resources (09/12/2005)

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BellSouth Telecomm. -- P-55, SUB 1541; P-35, SUB 101; P-100, SUB 133c; Order Grant. Authority to Transf. Portions of Certif., Customers & Assets, and Designating Carrier (03/24/2005)

Computer Network Tech. Corp. -- P-1285, SUB 2; Order Approv. Transf. of Control (03/15/2005)

Epicus, Inc. -- P-649, SUB 3; P-1380, SUB 0; Order Approv. Transfer of Assets, Customers and Certificates (12/05/2005)

Elantic Telecom. -- P-1136, SUB 3; Order Approving Transfer of Control (11/10/2005)

Excel Telecomm. -- P-270, SUB 15; Order Approving Transfer of Control (03/15/2005)

ICG Telecom Group, Inc. -- P-582, SUB 10; P-1202 SUB 5; Order Approv. Transfer of Certain Assets and Customers (05/26/2005)

InFlow -- P-979, SUB 3; P-1368, SUB 0; Order Approv. Transfer of Control &Certif. (09/12/2005)

Level 3 -- P-779, SUB 10; P-673, SUB 8; P-1327, SUB 1: Order Approv. Transf. of Control (11/22/2005)

Matrix Telecom -- P-224, SUB 10; P-698, SUB 5; P-843, SUB 3; Order Approving Requested Transfer (08/01/2005)

McLeodUSA Telecomm. -- P-617, SUB 4; Order Approv. Transfer of Control (11/10/2005)

Network Tel. Corp. - P-748, SUB 6; Order Approving Transfer of Control (11/22/2005)

Nuvox Comm. -- P-913, SUB 8; P-772, SUB 10; P-1341, SUB 0; Order Canceling Certificates and Recognizing Name Change (03/08/2005)

SBC Long Distance -- P-638, SUB 2; P-936, SUB 3; Order Approving Corporate Realignment Transactions (03/15/2005); Order Concerning Certificates (08/15/2005)

Southern Digital Network -- P-1314, SUB 3; Order Approv. Transfer of Control (11/04/2005)

Time Warner of N.C. - P-472, SUB 20; Order Approving Transfer of Control (11/04/2005)

TelCove Operations -- P-1020, SUB 5; P-824, SUB 7; Order Approv. Transfer of Certain Assets and Customers (05/26/2005)

TELECOMMUNICATIONS - Sale/Transfer (Continued)

Winstar Comm. -- P-1161, SUB 3; Order Approving Transfer of Control (09/12/2005)
IDS Telecom -- P-1032, SUB 4; P-1353, Sub 0; Order Approving Transfer of Assets, Customers and Certificates (05/10/2005); Errata Order (05/27/2005)

TELECOMMUNICATIONS – Securities

Ellerbe Telephone -- P-21, SUB 44A; Order Approving Loan Agreement Amend. (06/15/2005)
MEBTEL -- P-35, SUB 102; P-736, SUB 5; Order Approv. Transfer of Control (02/22/2005)

TRANSPORTATION

TRANSPORTATION - Common Carrier Certificate

Orders Granting Application for Certificate of Exemption - Issued

Company	Docket No.	Date
Absolute Movers, Brian Perkins, d/b/a	T-4298, SUB 0	(04/13/2005)
America's Best Moving System Charlotte; Apt. Movers Etc. of Charlotte, d/b/a	T-4300, SUB 0	(04/12/2005)
Ashby Bobbitt Enterprises, Inc.; Outer Banks Movers, d/b/a	T-4306, SUB 0	(08/25/2005)
Bevins, Ralph Wayne; Murphy Movers, d/b/a	T-4290, SUB 0	(03/02/2005)
Brooks, Floyd Allen, Jr.; Brooks Coast to Coast Transport, d/b/a	T-4292, SUB 0	(01/14/2005)
C & H Investment Group, Inc.; Tar Heel Moving & Storage, d/b/a	T-4295, SUB 0	(02/08/2005)
Carolina Transportation Systems, Inc.	T-4304, SUB 0	(05/03/2005)
Flat Rate Moving & Relocation, Inc., Flat Rate Moving Services, d/b/a	T-4275, SUB 0	(06/29/2005)
Jabear, Inc.; Move It Now, d/b/a	T-4296, SUB 0	(02/21/2005)
Johnnie Peele; Lil John Movers, d/b/a	T-4312, SUB 0	(10/19/2005)
Melton, Susan Bright; Bright's Moving, d/b/a	T-4302, SUB 0	(04/08/2005)
Monroe, Richard Hugh, Jr.; M & B Movers, d/b/a	T-4308, SUB 0	(09/14/2005)
Morehead Moving & Storage, Inc.	T-918, SUB 8	(06/06/2005)
McCarthy Moving Co., Inc.	T-4305, SUB 0	(05/19/2005)
Meticulous Movers, Inc.	T-4307, SUB 0	(09/07/2005)
New World Van Lines, Inc.	T-4291, SUB 0	(01/05/2005)
O'Donnell, Thomas Francis; Southport Furniture Delivery, d/b/a	T-4293, SUB 0	(01/24/2005)
Parks, Walter Randolph; Parks Transfer, d/b/a	T-4313, SUB 0	(10/11/2005)
Patterson, Andre Courtney; Mover's Choice, d/b/a	T-4268, SUB 0	(02/21/2005)
Peach Movers of North Carolina, Inc.	T-4309, SUB 0	(09/27/2005)
Redi-Care Movers, LLC	T-4303, SUB 0	(06/14/2005)
Reliable Furniture Carriers, Inc.	T-4299, SUB 0	(04/01/2005)

Shore, Samuel David; Shore To Shore Moving & Storage, d/b/a	T-4137, SUB 1	(03/08/2005)
Thomas, John E.; J. E. Thomas & Sons Moving, d/b/a	T-4311, SUB 0	(09/19/2005)
Unity Moving and Storage, Inc.	T-4289, SUB 0	(02/22/2005)

Johnson, Darryl Keith; On Time Moving & Delivery, d/b/a; T-4294, SUB 0, Order Allowing Withdrawal of Application and Closing Docket (02/23/2005)

TRANSPORTATION - Cancellation of Certificate

Orders Canceling Certificates of Exemption - Issued

Company	Docket No.	Date
A-1 Quality Moving Co.; Swofford, Inc., d/b/a	T-3969, SUB 1	(02/15/2005)
Abernethy Transfer & Storage Co.	T-744, SUB 6	(02/23/2005)
Advanced Installation Services, Inc.	T-3280, SUB 2	(09/08/2005)
Advantage Moving & Storage, Inc.	T-4119, SUB 3	(01/26/2005)
Americas Best Moving Systems, LLC; Apartment Movers Etc., d/b/a	T-4282, SUB 1	(09/08/2005)
Archie Thomas Bozovich; Bozovich Movers, d/b/a	T-3439, SUB 2	(03/31/2005)
Bright, Joe W.; Bright's Transfer, Moving & Storage, d/b/a	T-1288, SUB 5	(04/08/2005)
Cadillac Moving Services; Cadillac Transport Services, Inc., d/b/a	T-4162, SUB 2	(09/22/2005)
Discount Movers, LLC	T-4221, SUB 1	(09/01/2005)
Forsyth Initiative for Resid. Self Treatment; First Movers, d/b/a	T-4102, SUB 4	(05/31/2005)
Magnum Moving & Storage, Inc.	T-4089, SUB 3	(10/19/2005)
MPC Aviation, Inc.; Small Time Movers, d/b/a	T-2777, SUB 5	(01/26/2005)
Richard Marvin Hawkins, Jr.; R. M. Williams Moving Service, d/b/a	T-928, SUB 6	(06/07/2005)
Service Moving & Storage Co., Inc.	T-1582, SUB 3	(01/26/2005)
Tar Heel Moving & Storage Inc.	T-1471, SUB 3	(02/08/2005)

Barber, Walter; Barber's Moving & Storage Co., d/b/a -- T-4117, SUB 6; T-100, SUB 60; Order Affirm. Previous Comm. Order Cancel. Certificate of Exemption (01/07/2005)

Raleigh Express Delivery; Grady's Moving & Delivery; d/b/a -- T-4256, SUB 1; T-100, SUB 64; Order Affirming Previous Comm. Order Cancel. Certificate (11/14/2005)

Sam A. Byers & Sons Moving Service, Inc. -- T-4030, SUB 4; T-100, SUB 64; Order Affirming Previous Comm. Order Cancel. Certificate (11/14/2005)

Thomas Transfer -- T-885, SUB 5; T-100, SUB 64; Order Affirming Previous Comm. Order Cancel. Certificate (11/14/2005)

TRANSPORTATION - Name Change

A+ Relocation Serv.; A+ Moving & Storage, d/b/a; -- T-4247, SUB 1; Order Approving Name Change (08/29/2005)

ORDERS AND DECISIONS LISTED

TRANSPORTATION - Name Change (Continued)

AAA Moving & Storage -- T-4150, SUB 4; Order Approving Name Change (10/19/2005)

Hilldrup Co.; Hilldrup Moving & Storage, d/b/a -- T-4095, SUB 1; Order Approv. Name Change (10/06/2005)

TRANSPORTATION - Rate Increase

(Order Approving Fuel Surcharge – Orders Issued)

Rates-Truck -- T-825, SUB 339 (03/01/2005); (03/22/2005); (04/12/2005); (05/17/2005); (06/01/2005); (06/21/2005); (08/02/2005); (08/23/2005); (09/13/2005); (09/27/2005); (10/11/2005); (11/01/2005); (11/22/2005); (12/06/2005)

TRANSPORTATION - Reinstating Certificate

Stanley's Transfer -- T-1913, SUB 8; Order Rescind. Order Cancel. Certif. of Exempt. (03/11/2005)

TRANSPORTATION - Show Cause

Flat Rate Moving -- T-4240, SUB 2; Recom. Order Cancel. Certif. of Exemption (06/21/2005)

Hughes Logistics; Assoc. Specialties, d/b/a -- T-4173, SUB 2; Recom. Order Cancel. Certif. of Exemption (10/10/2005)

McCarthy Moving -- T-4305, SUB 1; Recommend. Order Cancel. Certif. of Exemption (08/29/2005

Monroe, R. H. & L. W. Bethea; M & B Movers, d/b/a -- T-4245, SUB 1; Recommended Order Cancel. Certificate of Exemption (01/10/2005

Moving Solutions -- T-4215, SUB 2; Recommend. Order Cancel. Certif. of Exemption (03/15/2005)

Patterson, A. C.; Mover's Choice, d/b/a -- T-4268, SUB 1; Recom. Order Cancel. Certif. of Exemption (08/01/2005)

Shore, Samuel D.; Shore To Shore Moving & Storage, d/b/a -- T-4137, SUB 2; Recommended Order Cancelling Certificate of Exemption (12/05/2005)

Tryon Moving & Storage – T-854, SUB 12; Order Rescind. Order Cancel. Certif. of Exempt. (06/06/2005)

TRANSPORTATION – Suspension

All American Movers of Goldsboro -- T-1934, SUB 2; Order Grant. Authoriz. Suspen. (07/28/2005)

Helms, Anna R., R D Helms Transfer Co., d/b/a -- T-4224, SUB 2; Order Granting Authorized Suspension (06/07/2005); Errata Order (06/07/2005)

Khenthennha Christine Keyton; Isaac's Moving Service, d/b/a -- Order Granting Authorized Suspension T-4200, SUB 2 (11/10/2005)

M. M. Smith Storage Warehouse -- T-916, SUB 4; Order Grant. Authorized Suspension (10/03/2005)

Mitchell, L.; Mitchell Movers, d/b/a -- T-4257, SUB 1; Order Grant. Authoriz. Suspen. (11/10/2005)

Muscle Movers -- T-4223, SUB 2 - Order Grant. Authoriz. Suspen. & Dismiss. Show Cause Order (12/16/2005)

Scott, W.; Bill Scott Trucking, d/b/a -- T-4281, SUB 1; Order Grant. Authoriz. Suspen. (03/09/2005)

Standard Moving & Storage -- T-492, SUB 7; Order Granting Authorized Suspension (07/28/2005)

TRANSPORTATION - Sale/Transfer

Ray Moving & Storage – T-945, SUB 8: T-945, SUB 9; T-4301, SUB 0; Order Approving Name Change & Sale & Transfer (05/16/2005)

Triad Moving & Storage -- T-4274, SUB 1; Order Approv. Transfer & Name Change (11/10/2005)

ORDERS AND DECISIONS LISTED

WATER AND SEWER

WATER AND SEWER - Bonding

A & D Water -- W-1049, SUB 7; Order Approv. Bond & Surety & Releas. Bond & Surety (11/29/2005)

A & D Water -- W-1049, SUB 8; Order Approv. Bond & Surety & Releasing Bond & Surety (11/29/2005)

Aqua North Carolina -- W-218, SUB 214; Order Approv. Corporate Surety Bond & Releasing Bond (06/06/2005)

Bradfield Farms Water. -- W-1044, SUB 7; Order Accept. Bond & Surety & Releasing Bond & Surety (06/22/2005)

CWS Systems -- W-778, SUB 63; Order Accept. Bond & Surety & Releasing Bond & Surety (06/22/2005)

Heater Utilities -- W-274, SUB 506; Order Approv. Corp. Surety Bond & Releas. Bond (01/24/2005)

Heater Utilities -- W-274, SUB 546; Order Approv. Corp. Surety Bond & Releas. Bond (10/28/2005)

Mountain Air Utilities -- W-1148, SUB 1; Order Approv. Bond & Surety & Releas. Bond & Surety (06/16/2005)

North Topsail Utilities -- W-1143, SUB 4; Order Accept. Bond & Surety & Releasing Bond & Surety (06/22/2005)

Winkler; C. K. -- W-1206, SUB 2; Order Approv. Bond & Surety & Releasing Bond & Surety (12/20/2005)

WATER AND SEWER - Certificate

(Orders Granting Franchise and Approving Rates)

Aqua North Carolina, Inc. -- W-218,
- SUB 194 (Normandy Glen Subdivision) (03/15/2005)
- SUB 196 (Lake Ridge Aero Park Subdivision) (02/21/2005)
- SUB 201 (Summerfield Farms Subdivision) (08/29/2005)
- SUB 202 (Ballard Farm Subdivision) (01/14/2005)
- SUB 208 (Armfield Subdivision -- Phases 1B, 3, 4, & 5) (06/08/2005)
- SUB 210 (Stirlingshire Subdivision) (05/26/2005)
- SUB 211 (Nantucket Village Subdivision) (05/26/2005)
- SUB 212 (Sanford's Creek Subdivision) (06/08/2005)
- SUB 219 (Belews Landing Subdivision) (08/03/2005)
- SUB 221 (Ridgecrest Subdivision) (08/29/2005)
- SUB 227 (Wellington Subdivision, a/k/a Bevill Lakes Farm Subdivision) (12/21/2005)

Banks; Parks -- W-1244,
- SUB 0 (Lakeview Mobil Home Park) (03/31/2005)
- SUB 1 (Brownwood Mobile Home Park) (03/31/2005)
- SUB 2 (Mountain Terrace Mobile Home Park) (03/31/2005)

Chatham Utilities -- W-1240, SUB 0 (Chatham Est. Manuf. Housing Comm.) (01/26/2005)

Duckett; Gordon & Susan -- W-1237, SUB 0 (Forest Ridge Mobile Home Park) (04/28/2005)

Fairways Utilities, Inc. -- W-787, SUB 23 (Seabreeze Sound Subdivision) (10/04/2005)

Hawk Run Development of Asheville -- W-1238,
- SUB 0 (Overlook Village Mobile Home Park) (09/20/2005)
- SUB 1 (Reynolds Mobile Home Park) (09/20/2005)

Heater Utilities, Inc. -- W-274,
- SUB 501 (Preserve at Isle of Pines Subdivision) (01/14/2005)

ORDERS AND DECISIONS LISTED

(Orders Granting Franchise and Approving Rates) (Continued)

Heater Utilities, Inc. -- W-274,
- SUB 507 (Copper Trace Subdivision, Phase 2) (03/31/2005)
- SUB 510 (Tradewinds Subdivision) (04/12/2005)
- SUB 513 (Parker Falls Subdivision) (03/31/2005)
- SUB 516 (Elliott Landing Subdivision) (03/31/2005)
- SUB 517 (Barrington Hills Subdivision) (03/31/2005)
- SUB 528 (The Preserve at Jordan Lake Subdivision) (08/26/2005)
- SUB 529 (Tavernier Subdivision) (08/04/2005)
- SUB 543 (Vintage Acres Subdivision) (12/13/2005)
- SUB 550 (Cane Creek Subdivision) (12/13/2005)

Mayfaire I, LLC -- W-1249, SUB 0 (Mayfaire Town Center & Comm. Center (12/13/2005)

Meadowlands Development – W-1259, SUB 0; (Meadowlands Subdivision) (11/22/2005)

North Carolina Water Utility & Assoc. – W-1204,
- SUB 3 (Asheboro Country Club Subdivision) (06/02/2005)
- SUB 4 (Rachel's Landing Subdivision) (09/29/2005)

Riverwalk Utilities -- W-1239, SUB 0 (River Walk Mobile Home Park) (06/16/2005)

Aqua North Carolina – W-218,
- SUB 178 (Bingham Woods) Recomm. Order Grant. Franchise & Approv. Rates (01/31/2005); Order Allow. Recomm. Order to Become Effect. & Final (01/31/2005)
- SUB 204 (Castle Bay Subd.) Recomm. Order Grant. Franchise & Approv. Rates (06/01/2005)

Bay Tree Utility Co. -- W-1080, SUB 0; Order Closing Docket (12/16/2005)

Chapman; R. & B. -- W-1247, SUB 0; Order Accept. Bond, Grant. Franchise, Approv. Rates, & Requiring Customer Notice (12/14/2005)

High Vista Serv. -- W-1203, SUB 0; Order Allow. Withdraw. of Application & Requir. Customer Notice (12/05/2005)

Mill Run Utilities -- W-1245, SUB 0; Recommended Order Grant. Franchise & Approving Rates (06/20/2005); Order Allow. Recommended Order to Become Final & Effective (06/20/2005)

North Chatham Utilities -- W-1256, SUB 0; Order Allow. Withdraw. of Application & Canceling Hearing (11/21/2005)

WATER AND SEWER – Complaint

Carolina Water Service of N.C. – W-354,
- SUB 262; Order Closing Docket (Complaint of James A. Stewart) (12/30/2005)
- SUB 264; Order Closing Docket; (Complaint of Verlander, Underwood, Bertocci, & Kulikauski) (12/30/2005)
- SUB 285; Order Dismissing Complaint & Closing Docket (Frances G. Hill) (03/03/2005)

Earth Environmental Services -- W-1129, SUB 2; Order Dismissing Complaint & Closing Docket (Mike Powell) (03/29/2005)

MECO Utilities -- W-1166, SUB 2; Order Dismiss. Complaint & Closing Docket (Fort) (06/24/2005)

Northwood Water Company -- W-690, SUB 3; Order Dismiss. Complaint & Closing Docket (Smith) (10/07/2005)

Carolina Water Service of N.C. -- W-354, SUB 171; W-354, SUB 256; Order Closing Docket (Complaint of C. Okoroji) (12/19/2005)

WATER AND SEWER - Contracts/Agreements

Bald Head Island -- W-798, SUB 9; Order Authoriz. Tariff Amendment (03/23/2005); Errata Order (03/29/2005)

WATER AND SEWER - Contracts/Agreements (Continued)

Carolina Water Service of N.C. - W-354, SUB 266; W-809, SUB 2; W-1044, SUB 9; W-1013, SUB 4; W-778, SUB 69; W-1058, SUB 2; W-1143, SUB 6; W-962, SUB 1; W-936, SUB 1; W-1151, SUB 1; W-1152, SUB 1; W-1012, SUB 5; Order Accepting Contract for Filing (07/28/2005)

WATER AND SEWER - Contiguous Water Extension
(Orders Recognizing Contiguous Extension and Approving Rates)

Aqua North Carolina -- W-218,
SUB 199; SUB 165 (12/21/2005); SUB 200 (04/26/2005); SUB 203; SUB 165 (12/21/2005); SUB 206; SUB 165 (12/21/2005); SUB 207 (08/10/2005); SUB 213 (06/08/2005); SUB 215 (07/21/2005); SUB 217 (08/03/2005); SUB 218 (08/03/2005); SUB 226; SUB 165 (12/21/2005); SUB 283 (05/03/2005)

Fairways Utilities -- W-787,
SUB 18 (02/01/2005); SUB 22 (03/22/2005)

Heater Utilities Inc. -- W-274,
SUB 499 (04/26/2005); SUB 505 (01/21/2005); SUB 508 (02/24/2005); SUB 509 (04/26/2005); SUB 512 (05/03/2005); SUB 514 (08/04/2005); SUB 515 (05/03/2005); SUB 519 (04/26/2005); SUB 521 (08/04/2005); SUB 523 (08/04/2005); SUB 524 (08/04/2005); SUB 525 (12/13/2005); SUB 526 (10/13/2005); SUB 530 (08/04/2005); SUB 532 (12/13/2005); SUB 533 (12/13/2005); SUB 534 (10/11/2005); SUB 535 (10/11/2005); SUB 537 (10/11/2005); SUB 539 (10/13/2005); SUB 541 (10/13/2005); SUB 542 (10/13/2005); SUB 552 (12/13/2005)

KDHWWTP, LLC -- W-1160,
SUB 2 (07/11/2005); SUB 5 (07/11/2005)

Pine Island-Currituck, LLC -- W-1072, SUB 9 (04/04/2005)

Transylvania Utilities, Inc. -- W-1012, SUB 6; Order Approving Contract (03/14/2005)

Carolina Water Service of N.C. -- W-354, SUB 221; Order Closing Docket (08/25/2005)

WATER AND SEWER – Discontinuance

Milstead Comm. Water System -- W-718, SUB 1; Order Authoriz. Discon. of Water Utility Serv. (06/15/2005)

River Run at Davidson -- W-1057, SUB 1; Order Canceling Franchise (06/07/2005)

Scotland Water Co. -- W-426, SUB 4; Order Canceling Franchises (04/26/2005)

Bach's Mobile Home Park - W-835, SUB 2; Order Discharg. Emerg. Operator & Discont. Water Utility Service (08/05/2005)

WATER AND SEWER - Emergency Operator

Community Water Works -- W-316, SUB 4; Order Appoint. Emergency Operator & Requiring Customer Notice (03/22/2005)

Hoopers Valley Water Co. -- W-794, SUB 4; Order Appoint. Emergency Operator & Requiring Customer Notice (10/07/2005)

Johnson & Perry Co -- W-998, SUB 0; Order Cancel. Temp. Operating Authority, Discharg. Emergency Operator, and Closing Docket (05/03/2005)

Patterson; James E. -- W-276, SUB 4; Order Cancel. Franchise, Discharg. Emergency Operator, and Requiring Customer Notice (10/10/2005)

ORDERS AND DECISIONS LISTED

WATER AND SEWER - Emergency Operator (Continued)

Santeetlah Shores, Inc. -- W-577, SUB 1; Order Authorizing New Connections, Approving New Connection Charge, and Authorizing Use of Funds (05/03/2005)

Viewmont Acres Water System -- W-856, SUB 7; Order Discharging Emergency Operator and Appointing Emergency Operator (11/03/2005)

WATER AND SEWER - Filings Due Per Order or Rule

Environ. Maintenance Sys. -- W-1054, SUB 7; Recomm. Order Granting Rate Increase (04/01/2005)

Heater Utilities, Inc. -- W-274, SUB 478; Order Grant. Partial Rate Increase and Requiring Customer Notice (04/18/2005); Errata Order (04/20/2005)

Jones Dairy Farm Utility -- W-898, SUB 4; Order Approv. Transf. & Cancel. Franchise (04/01/2005)

WATER AND SEWER – Miscellaneous

Bald Head Island Utilities -- W-798, SUB 10; Order Approv. Transfer, Cancel. Franchise, and Requiring Customer Notice (11/29/2005)

Concord Community Water System -- W-1232, SUB 0; Order Granting Request for Exemption from Regulation (05/03/2005)

Harrells Water Corp. -- W-1224, SUB 0; Order Granting Application for Deregulation (01/06/2005)

Kittrell Water Assoc. -- W-1219, SUB 0; Order Granting Application for Deregulation (01/06/2005)

West Iredell Water -- W-1235, SUB 0; Order Grant. Request for Exempt. from Regulat. (05/03/2005)

WATER AND SEWER - Rate Increase

Blue Creek Util. -- W-857, SUB 5; Order Allow. Withdraw. of Applic. & Requir. Customer Notice (08/22/2005)

Clarke Utilities -- W-1205, SUB 1; Order Approving Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice (09/14/2005)

Farm Water Works -- W-844, SUB 5 Order Closing Docket (04/19/2005)

High Hampton Inc. -- W-574, SUB 2; Order Cancel. Temp. Authority, Grant. Franchise, and Approving Rates (12/09/2005)

KDHWWTP, LLC -- W-1160, SUB 3; Order Granting Partial Rate Increase (05/31/2005)

KRJ Utilities -- W-1075, SUB 4; Order Grant. Partial Rate Increase & Requir. Customer Notice (01/14/2005); Errata Order (01/14/2005)

Scientific Water & Sewerage -- W-176, SUB 32; W-176, SUB 30; W-176, SUB 29; Order Consolidating Dockets (07/19/2005)

Silver Maples Mobile Estates -- W-776, SUB 4; Order Granting Rate Increase, Canceling Public Hearing, and Requiring Customer Notice (07/06/2005)

Whispering Pines Village, d/b/a; John D. Hook -- W-1042, SUB 3; Order Granting Rate Increase and Requiring Customer Notice (09/20/2005)

WATER AND SEWER - Sale/Transfer

A & D Water Service -- W-1049,

SUB 6; W-941, SUB 6; Order Approv. Bond, Approv. Transfer, Approv. Rates, & Requiring Customer Notice (11/29/2005)

SUB 6; W-941, SUB 6; Errata Order (12/08/2005)

WATER AND SEWER - Sale/Transfer (Continued)

Aqua North Carolina -- W-218,
SUB 198; W-380, SUB 6; Order Approving Transfer, Approving Rates, and Requiring Customer Notice (03/15/2005)
SUB 209; W-947, SUB 3; Order Approv. Transfer, Approv. Rates, & Requir. Customer Notice (10/10/2005)
SUB 216; W-1118, SUB 3; Order Accept. Bond, Approv. Transfer, & Requir. Customer Notice (12/09/2005)
Brook Arbor Co. -- W-1134, SUB 2; Order Approving Transfer (03/09/2005)
Carolina Water Service of N.C. -- W-354, SUB 290; Order Approv. Transfer, Cancel. Franchise and Requiring Customer Notice (09/26/2005)
Emerald Plantation Utility -- W-843, SUB 6; W-1211, SUB 0; Recommend. Order Approv. Rates & Requir. Customer Notice (03/23/2005); Order Allowing Recommend. Order to Become Final (03/23/2005)
Heater Utilities, Inc. -- W-274,
SUB 500; W-862, SUB 30; Order Approving Interim Rates as Final Rates (10/10/2005)
SUB 520; W-316, SUB 5; Order Approv. Transf., Approv. Interim Rates, Approv. Rate Base Treatment & Requiring Notice (06/17/2005)
SUB 527; W-690, SUB 5; Order Approving Transfer, Approving Rates, Approving Rate Base Treatment & Requiring Notice (09/30/2005)
North Chatham Holdings, LLC -- W-1118, SUB 2; Order Allowing Withdrawal of Application and Closing Docket (05/17/2005)

WATER AND SEWER - Tariff Revision for Pass-Through

Banks; Parks -- W-1244, SUB 4; Order Approving Tariff Revision (12/13/2005)
Christmount Christian Assembly -- W-1079, SUB 4; Order Approving Tariff Revision (08/04/2005)
Cogdill; Greg S. -- W-1171, SUB 3; Order Approving Tariff Revision (12/13/2005)
Comm. Investments - W-1158, SUB 4; Order Approv. Tariff Rev. & Req. Customer Notice (10/13/2005)
Duckett; Gordon & Susan -- W-1237, SUB 1; Order Approving Tariff Revision (12/21/2005)
Enviro-Tech of N.C. -- W-1165, SUB 1; Order Approving Tariff Revision (03/10/2005)
Homestead Comm. Water -- W-452, SUB 7; Order Approving Tariff Revision (08/05/2005)
Indian Creek Mobile Home Park -- W-1116, SUB 4; Order Approving Tariff Revision (12/21/2005)
Joyceton Water Works -- W-4, SUB 9; Order Approving Tariff Revision & Requiring Customer Notice (10/10/2005); Errata Order (12/02/2005)
KDHWWTP, LLC -- W-1160, SUB 4; Order Closing Docket (06/20/2005)
Laurel Wood Utilities -- W-1155, SUB 2; Order Approving Tariff Revision (12/21/2005)
Pine Island-Currituck Club -- W-1072, SUB 8; Order Approving Tariff Revision (03/10/2005)
Ridgecrest Water -- W-71, SUB 9; Order Approv. Tariff Rev. & Req. Customer Notice (04/26/2005)
Sandler Utilities at Mill Run -- W-1130, SUB 4; Order Approv. Tariff Rev. & Req. Customer Notice (03/14/2005)
Total Environmental Solutions -- W-1146, SUB 4; Order Approving Tariff Revision (08/30/2005)
Watercrest Estates - W-1021, SUB 6; Order Approving Tariff Revision (08/05/2005)
Wellington Mobile Home Park - W-1011, SUB 10; Order Approving Tariff Revision (08/09/2005)
Winkler; Carl K. - W-1206, SUB 3; Order Approving Tariff Revision (12/21/2005)

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Aqua North Carolina -- W-218, SUB 225; Order Restrict. Water Use & Req. Cust. Notice (09/23/2005)

Carolina Water Service of N.C. -- W-354, SUB 289; Order Extend. Restrict. of Water Use & Requiring Customer Notice (10/17/2005)

RESALE OF WATER AND SEWER

RESALE OF WATER AND SEWER - Cancellation of Certificate

CRIT-NC, LLC -- WR-39, SUB 52; Order Canceling Certificate of Authority (11/29/2005)
Monroe I, LLC -- WR-262, SUB 1; Order Canceling Certificate of Authority (03/09/2005)
Monroe II, LLC -- WR-263, SUB 1; Order Canceling Certificate of Authority (03/09/2005)
Oakwood Apartments II - WR-261, SUB 1; Order Canceling Certificate of Authority (03/09/2005)

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BRC Majestic Apartments, LLC	WR-374, SUB 0	(06/28/2005)
Brier Creek, LLC	WR-360, SUB 0	(05/24/2005)
Camden Operating LP	WR-42, SUB 19	(08/15/2005)
City View Associates, LLC	WR-346, SUB 0	(04/05/2005)
Copper Mill Village Apartments, LLC	WR-376, SUB 0	(07/12/2005)
CRIT-NC, LLC	WR-39, SUB 59	(11/29/2005)
CRIT-NC, LLC	WR-39, SUB 60	(12/05/2005)
CRLP NorthCreek Drive, LLC	WR-413, SUB 0	(12/05/2005)
Crossroads Ventures, LLC	WR-328, SUB 0	(01/05/2005)
Cypress Pointe Apartments, LLC	WR-359, SUB 0	(05/19/2005)
Davidson Income Real Estate, LP	WR-339, SUB 0	(01/25/2005)
Davis Commons Lexington, LLC	WR-410, SUB 0	(11/21/2005)
DDC Oxford Apartments, LLC	WR-398, SUB 0	(10/12/2005)
EWGP, LTD., Limited Partnership	WR-330, SUB 0	(01/05/2005)
Featherstone Village Apartments, LLC	WR-375, SUB 0	(07/07/2005)
Forest Durham Management, LLC	WR-358, SUB 0	(05/19/2005)
Forest Ridge Apartments, LLC	WR-357, SUB 0	(05/19/2005)
Fortress Highlands, LLC	WR-347, SUB 0	(03/21/2005)
Galleria Village Apartments, LLC	WR-367, SUB 0	(06/15/2005)
Harborside Commons Apartments, LLC	WR-366, SUB 0	(06/28/2005)
Heather Ridge Apartments, LLC	WR-356, SUB 0	(05/24/2005)
Heatherwood Kensington Apartments, LLC	WR-202, SUB 0	(01/19/2005)
Heatherwood Kensington Apartments, LLC	WR-202, SUB 1	(01/19/2005)
Hidden Creek Village Apartments, LLC	WR-377, SUB 0	(07/07/2005)
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Hunter's Chase, LLC	WR-348, SUB 0	(03/30/2005)
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Littlefield Enterprises Mooresville	WR-238, SUB 0	(01/19/2005)
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Northview Asheville, LLC	WR-355, SUB 0	(05/24/2005)
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Spanos Corporation; The	WR-11, SUB 8	(08/11/2005)
Salem Ridge/Shugart, LLC	WR-399, SUB 0	(10/10/2005)
Salisbury Apartments, LLC	WR-201, SUB 0	(01/04/2005)
Southern Village Apartments, LLC	WR-338, SUB 0	(01/25/2005)
Stonecreek Apartments of Mooresville	WR-390, SUB 0	(09/23/2005)
Tarrant Road Apartment Associates, LLC	WR-334, SUB 0	(01/05/2005)
TCR North Hills Limited Partnership	WR-385, SUB 0	(08/04/2005)
TCR South Square Limited Partnership	WR-386, SUB 0	(08/04/2005)
The Carlisle at Delta Park, LLC	WR-388, SUB 0	(08/15/2005)
The Vinings at University Center, LLC	WR-402, SUB 0	(10/31/2005)
Three Oak Property, LLC	WR-405, SUB 0	(11/22/2005)
Timber Crest Apartments, LLC	WR-412, SUB 0	(12/05/2005)
Transwestern Waterford, LLC	WR-423, SUB 0	(12/20/2005)
Transwestern Woodway Point, LLC	WR-424, SUB 0	(12/20/2005)
West Bloomfield Commons, LLC	WR-331, SUB 0	(01/05/2005)
Doggett, Livingston, Livingston, & Wilkinson	WR-350, SUB 0	(03/30/2005)
Woodland Park Apartment Property, LLC	WR-361, SUB 0	(06/02/2005)
Woodward Communities, LLC	WR-354, SUB 0	(05/11/2005)
Yarbrough Properties, LLC	WR-342, SUB 0	(02/09/2005)

AIMCO Belmont, LLC -- WR-370, SUB 0; WR-48, SUB 2; Order Granting Transfer of Certificate of Authority and Approving Rates (10/10/2005)

BES University Tower Fund III -- WR-365, SUB 0; WR-219, SUB 2; Order Granting Transfer of Certificate of Authority and Approving Rates (08/30/2005)

Crown Ridge Acquisition Co. -- WR-403, SUB 0; WR-40, SUB 2; Order Granting Certificate of Authority, Approving Rates and Canceling Certificate (11/15/2005)

CWS Apartment Homes -- WR-343, SUB 0; W-1135, SUB 1; Order Granting Certificate of Authority, Approving Rates, & Canceling Franchise (03/21/2005); Errata Order (03/23/2005)

CWS Crossroads 2000, LP - WR-351, SUB 0; W-1163, SUB 1; Order Granting Certificate of Authority, Approving Rates, and Canceling Franchise (04/05/2005)

Echo Forest, LLC -- WR-368, SUB 0; WR-27, SUB 5; Order Granting Transfer of Certificate of Authority and Approving Rates (06/15/2005)

Emerald Plantation -- WR-337, SUB 0; Order Disapprov. Applic. for Certi. of Author. (01/20/2005)

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Genesis Partners -- WR-323, SUB 1; W-1176, SUB 1; Order Grant. Certif. of Authority, Approving Rates & Canceling Franchise (03/21/2005)

GMC Charlotte, LLC -- WR-391, SUB 0; WR-3, SUB 94; Order Granting Certificate of Authority, Approving Rates and Canceling Certificate (09/08/2005)

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GMC Charlotte, LLC -- WR-391, SUB 1; WR-3, SUB 94; Order Granting Certificate of Authority, Approving Rates and Canceling Certificate (09/08/2005)

HD South Point, LLC -- WR-320, SUB 0; WR-165, SUB 1; Order Granting Transfer of Certificate of Authority and Approving Rates (05/19/2005)

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Mayfaire Apartments -- WR-345, SUB 0; Errata Order (03/21/2005)

Preston's Reserve L.P. -- WR-373, SUB 0; W-1126, SUB 1; Order Granting Certificate of Authority, Approving Rates & Canceling Franchise (07/07/2005)

Southern Village Apartments,LLC -- WR-338, SUB 0; Errata Order (01/26/2005)

Strawberry Hill Associates LP -- WR-293, SUB 0; Errata Order (01/05/2005)

The Tradition at Mallard Creek -- WR-353, SUB 0; W-1117, SUB 3; Order Granting Certificate of Authority, Approving Rates, and Canceling Franchise (04/20/2005)

USA Park Side Leaseco., LLC -- WR-381, SUB 0; WR-11, SUB 7; Order Granting Certificate of Authority, Approving Rates and Canceling Certificate (07/27/2005)

WMCi Charlotte VI, LLC -- WR-371, SUB 0; WR-82, SUB 4; Order Granting Transfer of Certificate of Authority and Approving Rates (07/12/2005)

Woodlands at Wakefield Plantation -- WR-372, SUB 0; W-1127, SUB 2; Order Granting Certificate of Authority, Approving Rates & Canceling Franchise (07/07/2005)

Woodward Communities, LLC -- WR-354, SUB 0; Errata Order (05/17/2005)

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Charlotte Cotton Mill, LLC	WR-166, SUB 1	(01/06/2005)
Forest Ridge, LLC	WR-171, SUB 1	(01/12/2005)
Lodge at Old Concord, LLC	WR-87, SUB 2	(03/02/2005)
Notting Hill, LLC	WR-68, SUB 2	(01/06/2005)
NPCA Limited Partnership	WR-140, SUB 1	(01/06/2005)
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UDR of NC, LP	WR-3, SUB 63	(03/03/2005)
UDR of NC, LP	WR-3, SUB 67	(02/28/2005)
UDR of NC, LP	WR-3, SUB 76	(01/19/2005)
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Bridgewood Title Partnership -- WR-132, SUB 3 (06/14/2005)
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CEG Jacksonville, LLC -- WR-50, SUB 5 (02/25/2005)
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Monroe-Oxford Associates L.P. -- WR-145, SUB 4 (09/13/2005)
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