JOINT LEGISLATIVE UTILITY REVIEW COMMITTEE

REPORT TO THE 1997 GENERAL ASSEMBLY OF NORTH CAROLINA

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March 27, 1997

TO THE MEMBERS OF THE 1997 GENERAL ASSEMBLY:

Pursuant to Article 12A of Chapter 120 of the North Carolina General Statutes, and Chapter 542 of the 1995 Session Laws, the Joint Legislative Utility Review Committee herewith submits its report to the General Assembly.

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INTRODUCTION

The Joint Legislative Utility Review Committee is a permanent committee of the General Assembly, as provided in Article 12A of Chapter 120 of the General Statutes. The Committee consists of ten members, five each from the Senate and the House of Representatives. The House members are appointed by the Speaker of the House. The Senate members are appointed by the President Pro Tempore of the Senate. Members must be sitting members of the General Assembly. They serve at the pleasure of the appointing officer. A Senate cochairman and a House cochairman are designated by the respective appointing officer.

The general purpose of the Committee is to evaluate the actions of the State Utilities Commission and the Public Staff, and to analyze the operations of the utility companies operating in North Carolina. The Committee also stays abreast of regulatory changes relating to utilities at the federal level, judicial decisions, and technical changes affecting utilities. The Committee is authorized to make reports and recommendations to the General Assembly, from time to time, on matters relating to the powers and duties of the Committee (G.S. 120-70.3(7)).

The stated powers and purposes of the Committee include undertaking specific studies as may be requested by the President Pro Tempore of the Senate, the Speaker of the House of Representatives, the Legislative Research Commission, or either House of the General Assembly (G.S. 120-70.3(8)).

The General Assembly specifically authorized the Committee to study issues related to calculating avoided costs for small power producers, and authorized the

Committee to report any findings and recommendations to the 1997 General Assembly. (Appendix A.)

This report of the Joint Legislative Utility Review Committee is made in response to the specific authorization of the General Assembly, and as part of the Committee's general and ongoing obligation to provide information and recommendations to the General Assembly relating to public utilities. It covers the period of time from the Committee's 1996 report, which ended with activities on April 26, 1996, through January 14, 1997.

AVOIDED COST - PAYMENTS TO SMALL HYROELECTRIC POWER PRODUCERS

Recommendation of the Committee

The Joint Legislative Utility Review Committee makes no recommendation to the General Assembly. The Committee notes that there is currently a proceeding underway before the North Carolina Utilities Commission to determine avoided cost payments to small hydroelectric power producers for the next two years. The Committee Staff will advise the Committee of the results of that proceeding when it is concluded.

Background

The Public Utilities Regulatory Policies Act of 1978 (PURPA) requires electric utilities to purchase electricity from generators known as qualifying facilities. These are cogeneration facilities and small power production facilities. G.S. 62-156 requires the North Carolina Utilities Commission to determine the rates to be paid by electric utilities for purchases of electricity from small power producers in North Carolina. Under North Carolina law, small power producers are hydroelectric facilities of 80 megawatts or less. The determination of these rates takes place in a biennial proceeding. The parties may contract for a different rate than the rate determined by the Comission.

Under PURPA, and under G.S. 62-156, the amount paid by the electric utility to the small hydroelectric facility may not exceed the avoided cost to the utility. Avoided cost is the cost to the electric utility of the electric energy which, but for the purchase from the small power producer, the utility would generate or purchase from another source. While the rate paid by the electric utility may not exceed avoided cost, there are differences in the methods which may be used to calculate avoided costs.

At its meeting on January 14, 1997, the Committee heard from all parties with an interest in this issue. The representatives of the small hydroelectric generating facilities testified that, based upon the payments being made to them pursuant to the Commission's avoided cost order currently in effect, they could not make a profit. They suggested an alternate method of calculating the rates paid to them. Their proposal would require the utility to meter the power produced by the small power producer, with its value set at the "retail" rate per kilowatt hour as approved by the Commission for the electric utility. The utility would keep a specific portion of the money for itself, covering profit and overhead, and the balance would be remitted to the small hydroelectric producer. A copy of the proposal put forth by the small hydroelectric generators is found in Appendix B.

The Honorable Allyson K. Duncan, of the North Carolina Utilities Commission, testified before the Committee and explained the methods the Commission has used to calculate avoided cost. She pointed out that the Commission is in the midst of the biennial proceeding to determine avoided cost rates for the next two-year period. The Commission has specifically required the electric utilities to address issues relating to:

1. Encouraging hydrogeneration by calculating avoided cost rates based on higher performance adjustment factors;

2. Whether to consider the direct and indirect costs of air pollution, nuclear decommissioning, and other costs that may be avoided because of hydrogeneration; and

3. Appropriate terms and conditions for offering long term avoided cost rates to small hydroelectric producers.

Commissioner Duncan closed her remarks by pointing out that the discussion of electric utility restructuring presently going on in Congress may well involve the repeal or alteration of PURPA. Commissioner Duncan's remarks are found in Appendix C of this report.

Mr. Robert Kaylor represented Duke Power Company and North Carolina Power Company before the Committee. He pointed out that the Federal Energy Regulatory Commission (FERC) has consistently ruled that states may not establish required payments to qualifying facilities that would exceed a utility's avoided cost. It is the position of Duke Power and North Carolina Power that the proposal of the hydroelectric generators would result in payments above avoided cost. He also pointed out that the rates paid to these facilities for electricity are reflected in the rates ultimately charged to customers of the electric utility. Electric utilities did not encourage the small hydroelectric developers to make investments in hydroelectric facilities. When Federal law and state law first required the electric utilities to purchase power from the small hydroelectric producers, the cost of electricity was high and, therefore, the payments to small hydroelectric producers were high. However, the cost of electricity has gone down due to lower fuel costs and lower inflation. This, in turn, has resulted in the avoided cost being less. Mr. Kaylor pointed out that the question of whether or not special provisions should be made to preserve the small hydroelectric facilities is a social issue. If society believes it is beneficial to preserve these facilities, then society as a whole should provide the compensation necessary to do so. The burden should not be placed on the electric utilities and, ultimately, the customers of those utilities.

Mr. Len Anthony represented Carolina Power & Light Company before the Committee. He pointed out that the method proposed for calculating the payments to the small hydroelectric producers would be inappropriate because basing them on the retail rate charged to the utility customers ignores other costs of doing business such as distribution, metering, billing and collection, taxes, insurance, and so on. PURPA, and the North Carolina law, requires the Utilities Commission to establish avoided cost rates equal to the costs the utility can avoid by purchasing the electricity rather than generating it. The method proposed by the hydroelectric generators would not be based upon that methodology. Mr. Anthony pointed out that CP&L has not had a general rate increase since 1988, and in real dollars, CP&L's residential rates are more than 6% lower than they were in 1990.

Gizele Rankin, an attorney with the Public Staff, also reviewed some of the history involved in the development of the small hydroelectric industry and the methods of paying these power producers. One factor, in particular, that she believes the Utilities Commission should alter in calculating avoided cost has to do with the performance factor adjustment presently in effect. It requires the small hydroelectric operators to operate 83% of the on-peak hours. Evidence in prior proceedings indicates that the operations of the small hydroelectric generators in North Carolina are constrained by lack of rainfall. This is a particular problem during the summer on-peak hours. A performance adjustment factor that took this dependence on natural conditions into account, would result in higher payments to the small hydroelectric generators, while remaining within the bounds of the avoided cost formula.

It is expected that the Utilities Commission will issue its avoided cost order, which will have considered the performance factor, as well as other issues, in April of 1997.

OTHER ACTIVITIES OF THE COMMITTEE

At its meeting on January 14, 1997, the Committee officially received the biennial gas expansion reports of the North Carolina Utilities Commission and the Public Staff. These reports are required to be presented to the Committee pursuant to G.S. 62-36A. G.S. 62-36A requires the natural gas local distribution companies to file biennial reports with the Utilities Commission detailing each company's plans for providing natural gas service in areas of its franchise territory in which natural gas service is not available. These reports are updated every two years. The Utilities Commission and the Public Staff are required by that statute to independently provide analyses and summaries of those reports, together with status reports of natural gas service in North Carolina, to the Committee. Of interest is the fact that two amendments were added to G.S. 62-36A by the 1995 General Assembly. The first amendment requires the expansion of natural gas service by each of the local distribution companies to all areas of their franchise territories by July 1, 1998 or within three years of the time the franchise territory is awarded, whichever is later. Any company which the Commission determines is not providing adequate service to at least some portion of each county within its territory by that time, forfeits the exclusive franchise rights to that portion of the territory not being served. The other amendment required the Commission to ensure that every county in the State was franchised to a natural gas local distribution company not later than January 1, 1997.

The reports of the Utilities Commission and the Public Staff were presented by Commissioner Laurence A. Cobb, and Robert Gruber, Executive Director of the Public Staff. To avoid a duplication of effort, Commissioner Cobb concentrated on the assignment of the unfranchised areas of the State, which has been completed, and the expansion activities of the natural gas local distribution companies. Mr. Gruber concentrated on the financial strength of the natural gas local distribution companies as it relates to the provision of service in their franchise territories. A copy of Commissioner Cobb's statement is contained in Appendix D. A copy of Mr. Gruber's statement is contained in Appendix E.

At the January 14, 1997 meeting the Committee received a report from Utilities Commission Chairman Joanne Sanford regarding the Utilities Commission's ongoing activities implementing local telecommunications competition pursuant to legislation passed by the 1995 General Assembly (House Bill 161). The Committee also received a brief report concerning the merger of MCI and British Telecommunications.

APPENDIX A

Subpart B, Part XX, Chapter 542 of the 1995 Session Laws

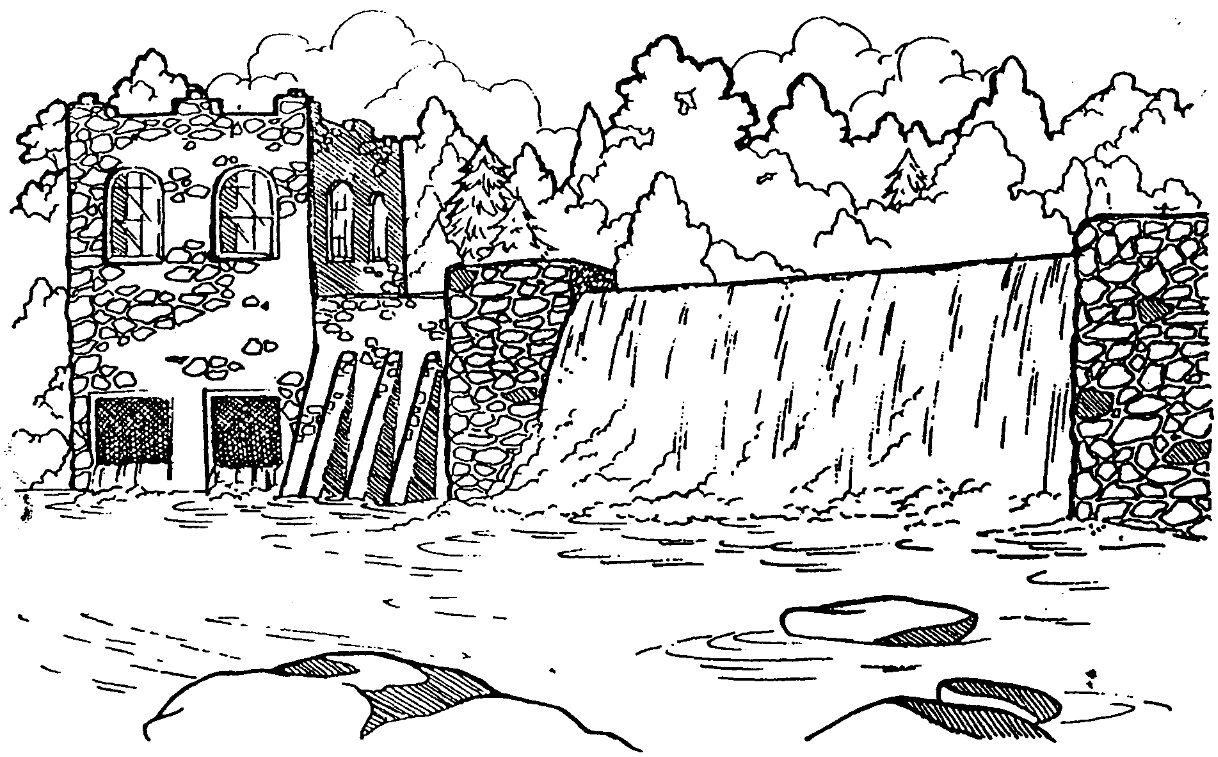
Subpart B. Utility Energy Cost (H.B. 931 - Allred)

Sec. 20.3. The Joint Legislative Utility Review Committee is authorized to study the issues related to calculating avoided costs for small power producers and may recommend any needed changes to the General Assembly.

Sec. 20.4. The Committee is authorized to report any findings and recommendations under this subpart to the 1997 General Assembly and may make an interim report, including any recommended legislation, to the 1996 Regular Session of the 1995 General Assembly.

APPENDIX B

North Carolina
Small Hydro



Clean Electricity from Renewable Natural Resources

A PROPOSAL FOR FAIR TREATMENT OF SMALL HYDROELECTRIC GENERATORS

Beginning this year North Carolina's small hydroelectric generators will be systematically forced out of business unless a fair way to compensate them for their electricity is adopted.

In the early 80's the average avoided cost was about five to six cents per kilowatt. Now it is down to just over 2.7 cents, about a 50% reduction in the claimed cost of making electricity. If small hydro projects are forced to accept new contracts under the avoided cost scheme, they will only receive about half for their power what they did 15 years ago. Clearly, they cannot survive at this rate.

The avoided cost scheme works for the utilities, and it can work for big thermal generators, who can choose when and how much to run. It will not work for small hydro. We are inherently limited in size, and when and how much power we can make. We cannot manipulate the streamflow to take advantage of marketplace incentives like the coal and gas burners can, or make water appear when it isn't there.

But, small hydro is worth keeping. Once small hydro is finished with its fuel, you can drink it! Its not dangerous, doesn't have to be buried for a thousand years, and, doesn't pollute the air. We save more than 36,000 tons of coal and prevent the emission of more than 60,000 tons of pollutant every year.

Beyond the fact that the retrograde evolution of the avoided cost scheme threatens to destroy us, nothing has changed with respect to the value of clean, hydroelectric generation. We still need to use our cleanest power first, to conserve our fossil fuels, to reduce our dependence of foreign oil, and reduce the amount of pollutants expelled into the air and water by large power plants.

By ignoring the hidden costs attendant to fossil fuel and nuclear generation, among other ways, the utilizes have managed to reduce the claimed avoided cost to a level so low that if small hydro is forced to accept it our projects cannot survive. If the utilities get their way, they may save some money, but, for that saving, North Carolina's only viable natural resource energy resource will be lost.

To preserve small hydro, a different, fair method of payment for its power is needed. General Statute 62-156 says:

> (a) In the event that a small power producer and an electric utility are unable to mutually agree to a contract for the sale of electricity or to a price for the electricity....... the Commission shall require the utility to purchase the power under rates and terms established in subsection (b) of this section.

Subsection (b) invokes (essentially) PURPA.

G.S. 62-156 does not require a contract to be under PURPA. Only if an agreement can't be reached is PURPA, and the complicated avoided cost scheme invoked.

Put another way, if a mutually agreeable arrangement between a small power producer and a utility can be had outside of PURPA, North Carolina law already permits it.

Our suggestion employs the simple expedient of replacing the complicated avoided cost scheme with a simple, fair system under which everyone, including the public, may benefit.

It revolves around what we call "non-specific" access to the marketplace, coupled with certain non-proliferation limitations designed to protect us and the public from future problems arising from complex rate fixing schemes, and fair payments to the utilities for their participation.

The schematic on following page shows the mechanics of the current system. Out plan doesn't change it. The utilities would continue to meter, distribute, bill, collect, and disperse payments, in a fashion similar to what they do now under the more complex rate fixing scheme. The physical equipment and logistical support is already in place.

The utility would meter our production into the pool of electricity in the grid. Each month they would calculate how much power the small project had contributed to the pool, and the value of it at the retail rate per kilowatt approved by the Commission for the receiving utility. The utility would keep a specific, portion of the money for itself, and remit the remainder to the small power producer.

As an example:

> Say the retail rate of the receiving utility is 7.15 cents per kilowatt hour, the 1993 Duke Power residential rate. The utility would deduct 12% for its profit, leaving roughly 6.29 cents. Then they would deduct another 12% from 6.29 cents, leaving 5.53 cents. It would be this amount, 5.53 cents per kilowatt hour, times the number of kilowatt hours contributed by the small power producer to the pool, that the utility would remit to the small power producer.

This system would have a negligible monetary effect on the consumer and the utility. On average the utilities already pay small hydro about 5 to 6 cents per kilowatt hour. That wouldn't change significantly. From the customer's standpoint, neither his rate or the amount of his bill would change.

Relatively, the amount of money at issue is small compared to the total amount paid by rate payers across the state.

The utilities (CP&L and Duke Power) sell about seven billion dollars worth of electricity a year. The collective annual income for small hydro is about three million dollars, or about .000428 (one four hundred and twenty-eight ten-thousandths) of the amount taken by the utilities. That's about one forty-two one-thousandths of one percent of the utilities electricity sales.

However, at issue is only the difference what small hydro receives now and the 2.7 cents per kilowatt hour that the utilities want to pay us, about 1.5 million dollars. Compared to 7 billion dollars, that amounts to one twenty-two one-thousandths of one percent of the utilities' income. The effect of numbers this tiny have no potential to make or break the utilities, but it can absolutely destroy small hydro.

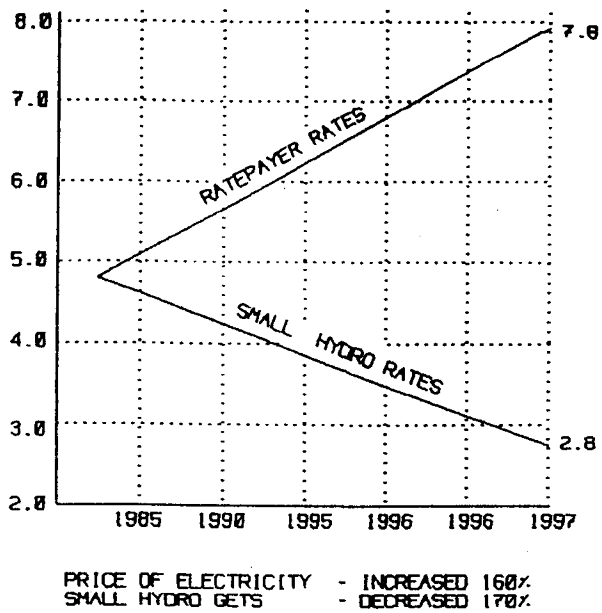
Our system offers simplicity. It will save the Utilities Commission both time and money while treating everyone fairly and protecting the diversity of power resource. It leaves the avoided cost structure intact, to deal with large projects which justify its high cost of administration, projects for which the game may be worth the candle.

We propose that our system be limited to small renewable resource power producers of 5 megawatts or less. Currently North Carolina law defines a small power producer as being 80 megawatts or less.

Our proposal ties our compensation directly to the retail rate for electricity. From that connection it derives both fairness and stability. We get a living wage for our project that more accurately reflects the true value of our product. The Utilities Commission assures that the retail customer gets a fair shake by setting the retail rates, and if the ratepayer gets a fair shake, we will. If the retail rate falls, our pay falls. If the value of electricity rises, we will not be not be subject to manipulation which causes such increases to pass us by.

Thank you for your attention.

Tim Henderson
for: H&H Properties and
North Carolina Small Hydro Electric Producers Association.



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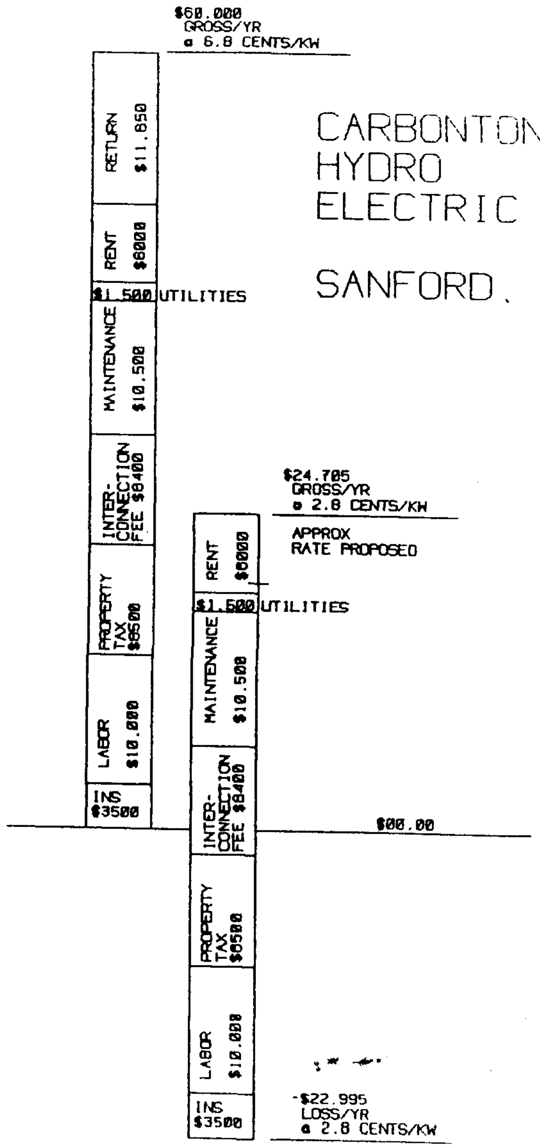

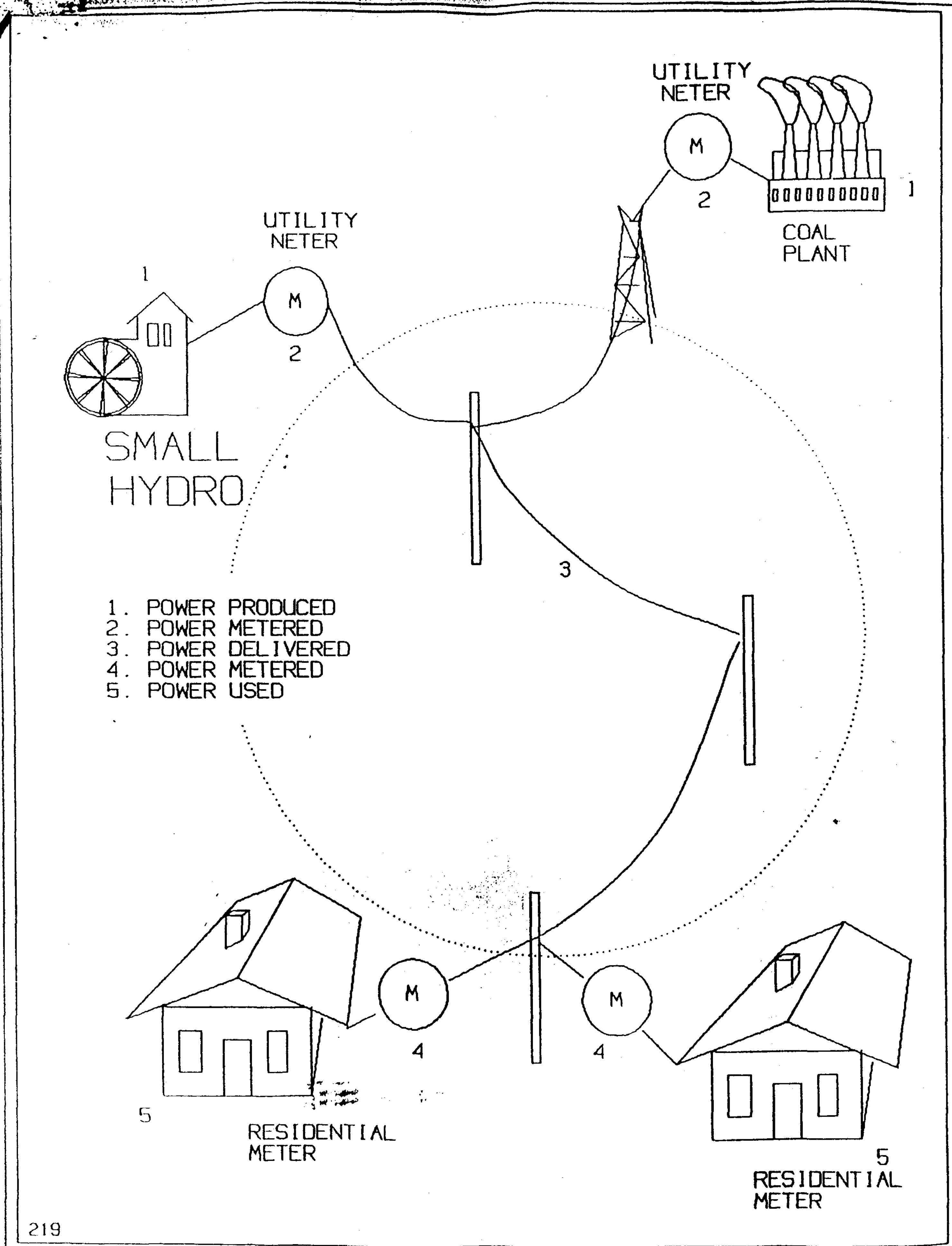
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Commr. Duncan 1/17/97

APPENDIX C

STATEMENT TO THE JOINT LEGISLATIVE UTILITY REVIEW COMMITTEE ON AVOIDED COSTS FOR HYDROELECTRIC QUALIFYING FACILITIES

January 14, 1997

Background

The Public Utilities Regulatory Policies Act of 1978 (PURPA) required each electric utility to purchase electricity from qualifying facilities (QFs), which are defined in PURPA as cogeneration and small power production facilities. Generally speaking, cogeneration facilities are nonutility plants that simultaneously produce two forms of energy, such as electric power and steam, while meeting certain thermal efficiency standards, including the use of five percent of its energy for commercial or industrial processes. Cogeneration facilities should use less fuel than would be required to produce electricity and steam separately. Small power production facilities are plants which use biomass, waste, or renewable resources like wind, water, and solar to produce electricity while meeting certain size and ownership standards. Reliance on these renewable resources of energy serves to reduce the use of scarce resources such as coal and oil. The hydroelectric facilities that we are considering today are small power producers under PURPA.

The Federal Energy Regulatory Commission (FERC) was required by PURPA to prescribe rules governing electric utility purchases from qualifying facilities. The FERC regulations require electric utilities to purchase electricity from qualifying facilities at rates that reflect the avoided costs of the respective utility. The FERC defined avoided costs as the costs that the purchasing utility can avoid as a result of obtaining energy and capacity from a given supplier rather than generating an equivalent amount of energy and capacity itself or purchasing the energy and capacity from alternative suppliers.

Implementation of the FERC rules was delegated to the State regulatory authorities. The N.C. Utilities Commission has since established separate avoided cost rates for each electric utility operating in North Carolina, and has revised such rates every two years. The Commission reviews the avoided cost rates of each utility, including contractual arrangements, interconnection charges, terms and conditions of service, and related matters by holding biennial proceedings.

G.S. 62-156 provides that, beginning no later than March 1981 and continuing at least every two years thereafter, the Utilities Commission shall determine the rates to be paid by electric utilities for purchases of electricity from small power producers in North Carolina. North Carolina law defines a small power producer as a hydroelectric facility of 80 megawatts or less capacity. The definition of small power producer under state law is more restrictive than the PURPA definition in that it includes only hydroelectric facilities of 80 megawatts or less capacity while excluding other types of renewable resources that are included in the PURPA definition.

The Utilities Commission establishes rates pursuant to G.S. 62-156 in the same biennial proceedings in which rates are established pursuant to PURPA. The rates established pursuant to G.S. 62-156 are based on the avoided costs of each utility, in the same manner as the rates established pursuant to PURPA.

Avoided Cost Rates

The Commission establishes avoided cost rates utilizing methodologies that are generally accepted and used throughout the electric utility industry. For example, CP&L and Duke have utilized the "peaker" methodology. The peaker methodology utilizes the cost of a peaker-type generating facility, typically a 75 to 100 megawatt combustion turbine unit, to determine avoided capacity costs. Avoided energy costs are calculated using a cost simulation model to analyze marginal system running (fuel and operation and maintenance) costs, in order to determine the degree to which these running costs change if a block of power displaces some of the utility's generation. The sum of the avoided capacity costs and the avoided energy costs is the utility's total avoided costs. Theory underpinning the peaker method indicates that the avoided cost determined using the peaker method will equal the avoided cost of a baseload unit. This is true because the lower capital costs of the peaker or combustion turbine are offset by the fuel and other operation and maintenance expenses included in the utility's system marginal running costs, which are higher for a peaker than for a baseload unit. The peaker method was developed by the National Economic Research Associates, Inc. (or NERA), when sponsored by the National Association of Utility Regulatory Commissioners, among others. N. C. Power has utilized the Differential Revenue Requirement (DRR) methodology in each of the past several biennial proceedings. The DRR methodology involves a comparison of the revenue requirements of a utility which result from two alternative system expansion plans - one including a block of new power purchased from outside suppliers and the other excluding purchase of 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 these 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 the QF capacity. Advocates of the use of the DRR method claim that the DRR methodology is fairly intuitive and straightforward, i.e., it provides an easily understood picture of what costs are avoided when QF power is acquired by the utility, and some other source of power is displaced or avoided. The Commission heard extensive testimony and comment on the relative merits of those methodologies versus others, and it determined that a common methodology should not be mandated for all utilities to use. It found that there are widely divergent opinions even among those who are most expert in these matters as to what costs are actually avoided and what methodologies will best identify those costs. It concluded that each utility should be allowed to generally pursue its own preferred method for calculating avoided costs, subject to the ongoing review and discussion of details of each methodology in the biennial proceedings.

A major issue in establishing avoided cost rates has been the determination of long-term avoided cost rates applicable over the next five, ten, or fifteen years, versus avoided cost rates that will be applicable over the two-year interval between biennial proceedings. In general, the Commission has established long-term avoided cost rates for qualifying facilities under PURPA having five megawatts or less capacity, and for small power producers under G.S. 62-156, having 80 megawatts or less capacity.

A controversial issue in establishing avoided cost rates has been the determination of avoided cost rates for capacity versus energy. In general, the Commission has established capacity payments that are paid only for electricity supplied during the purchasing utility's on-peak hours, plus additional energy payments that are paid for all electricity supplied during both on-peak and off-peak hours.

Another issue concerns the appropriate level of what is referred to as a "performance adjustment factor" used to calculate the capacity credits paid to QFs. The Commission has found that a purpose of the performance adjustment factor is to allow a QF to experience some level of outages and still receive the entire capacity credit payment based on the utility's avoided capacity costs. Without a performance adjustment factor, a QF would have to run 100 percent of the time during peak hours to receive its full capacity credit payment. It should be noted that the utility's own plants are not available or used during all peak hours. The Commission has used a 1.2 performance adjustment factor in establishing the utility's avoided cost capacity payments in each of the last several proceedings. A performance adjustment factor of 1.2 requires a QF to operate 83% of the purchased utility's on-peak hours to earn the entire capacity credit based on the utility's avoided cost.

In the last biennial proceeding, the issue was raised of whether small hydroelectric facilities should be required to operate 83% of peak hours in order to receive the full capacity payment. Hydro facilities are typically constrained by rainfall over which they have no control, so they do not normally operate 83% of the on-peak hours. In the last biennial proceeding, the Public Staff proposed that a different performance factor be applied to hydros in order to address this problem. However, the Public Staff's proposal in this regard was tendered in its proposed order which was submitted after the evidentiary record was closed. While the Commission did not accept the Public Staff's recommended performance adjustment factor, the Commission Order establishing the current biennial proceeding, required parties to address the merits of encouraging hydro generation by calculating avoided cost rates for hydros based on higher performance adjustment factors. The issue will be addressed again in the current biennial proceeding.

Current Biennial Proceeding

The Commission established the current biennial proceeding to determine avoided cost rates in Docket No. E-100, Sub 79. The electric utilities were required to file their proposed rates, standard contract forms and supporting work papers and comments for purchases from qualifying facilities by November 4, 1996. All other parties filed their reply comments and other proposals yesterday. The proceeding will also include another round of comments, a public hearing for taking non-expert public witness testimony on February 4, 1997, and proposed orders by March 4, 1997.

The Commission has required the electric utilities to include statements in their current filings discussing: (1) the merits of encouraging hydro generation by calculating avoided cost rates for hydro QFs based on higher performance adjustment factors; (2) the direct and indirect costs of air pollution, nuclear decommissioning, and other costs that are avoided because of hydro generation on the utilities' respective systems; and (3) appropriate terms and conditions for offering long-term avoided cost rates.

Federal Pre-emption

The question of whether the General Assembly may, by state statute, give hydro projects a premium in the determination of avoided cost rates is not as simple as it may seem at first. The FERC has held that a state may not set rates for qualifying facilities subject to PURPA in excess of avoided costs. The FERC first made this decision in 1988 in the case of a program under state law in New York that set a minimum rate of 6¢ per kWh for certain generating facilities and provided for utilities to pay this rate, even if it exceeded avoided cost, in order to encourage alternative energy sources. In a more recent case, FERC dealt with a Connecticut statute that required utilities to purchase energy from a resources recovery facility owned by a municipality at the same rate that the utility charged the municipality for electricity. FERC held that a state may not, even under its own authority, exceed the full avoided cost allowed by federal law for purchases of electricity from a qualifying facility. To the extent it does so, it is pre-empted by federal law.

However, the concept of avoided cost is flexible; there are many methods for determining avoided cost and PURPA allows the states quite a bit of freedom in determining the method they will each use. Thus, to the extent that the Commission might adopt a methodology for determining avoided cost rates that yields a higher figure for hydros, that would arguably not violate the federal law. This possibility has not been fully explored in the Commission's prior avoided cost proceedings, but this is essentially what the Public Staff is attempting to do in the comments that it has filed in the Commission's current avoided cost proceeding. The Commission will be deciding soon whether it agrees with the Public Staff's proposal.

The Future of PURPA

Lastly, I might add that PURPA may be repealed. In the last session of Congress, at least one bill was introduced which would have restructured the electric utility industry to promote competition and eliminated the utilities' obligation to purchase QF power once competition was achieved. Some members of Congress have indicated that electric utility restructuring is a high priority in the current session. Thus, it is certainly possible that PURPA may not survive long, at least not in its current form.

STATEMENT OF COMMISSIONER LAURENCE A. COBB TO THE JOINT LEGISLATIVE UTILITY REVIEW COMMITTEE ON RECENT NATURAL GAS ACTIVITIES AT THE UTILITIES COMMISSION

January 14, 1997

I am here today to report to the Committee on two matters related to natural gas service in the State. First, I will report on the Commission's assignment of previously unfranchised areas of the State for natural gas service. Second, I will summarize the reports that the natural gas utilities recently filed with the Commission dealing with their plans for expanding service in their franchised territories.

Assignment of Unfranchised Areas of the State

On June 12, 1995, the North Carolina General Assembly enacted legislation requiring the Utilities Commission to issue franchises by January 1, 1997, for all areas of the State which had not previously been franchised for natural gas service. Shortly after enactment, the Commission issued an Order opening a proceeding to implement the statute. That Order first allowed time for anyone who wanted to file an application for a certificate to provide natural gas service to any unfranchised area of the State. The Order then provided that if there were areas for which no application was filed, the Commission would assign these areas on a county-by-county basis to one of the existing natural gas utilities in the State.

The Commission received two applications pursuant to that Order. In December 1995, North Carolina Gas Service filed an application for a certificate for all of Stokes County not already franchised to it. (N.C. Gas already had a franchise for the southeast corner of Stokes.) On the same day, Piedmont Natural Gas Company filed an application for a certificate to serve the southwest corner of Stokes County. Those two applications were consolidated for hearing and hearings were held in May and June 1996. Recently, the Commission issued two orders dealing with Stokes County. On October 25, 1996, the Commission issued an Order granting the application filed by Piedmont and denying the application of N.C. Gas. Since Piedmont had asked for only the southwest corner of Stokes County in its application, the Commission's October 25 Order left a part of the county still unfranchised. The Commission issued an Order on December 12 assigning the remainder of Stokes County to Piedmont contingent on the October 25 Order withstanding appeal. N.C. Gas has appealed the October 25 Order to the appellate courts.

In the meanwhile, in May 1996, the Commission issued an Order dealing with all the other unfranchised areas of the State. The Commission made preliminary assignments of these areas and provided that any company could file protests or comments as to the preliminary assignments. No comments were filed, and the Commission issued a Final Order on August 16, 1996, making final assignments and issuing certificates of public convenience and necessity.

The map that has been provided to the Committee illustrates the assignments made by the Commission. The unfranchised areas of the State that were assigned by the Commission's August 16 Order are (1) the far western counties of Cherokee, Graham, Swain, Jackson, Macon and Clay; (2) the western counties of Madison, Yancey, Mitchell and Avery; (3) the northwestern counties of Ashe and Alleghany; (4) the northeastern counties of Camden, Currituck, Dare and Tyrrell; and (5) parts of Montgomery and Moore Counties. For the most part, these counties were assigned based on their proximity to existing natural gas facilities and existing territories of the natural gas utilities.

For example, the Commission assigned the far western counties of Cherokee, Graham, Swain, Jackson, Macon and Clay to Public Service Company. This assignment was primarily made because these counties are contiguous to Public Service's existing territory in western North Carolina. For the same reason, the Commission assigned Madison County to Public Service.

The Commission assigned Yancey, Mitchell and Avery Counties to Piedmont Natural Gas Company. These counties were assigned to Piedmont because they are close to Piedmont's existing territory and because Piedmont has an expansion fund with a considerable balance available for expansion purposes.

The northwestern counties of Ashe and Alleghany were assigned to Frontier Utilities of North Carolina. These counties are contiguous to territory previously franchised to Frontier. The previous franchise granted to Frontier is of course subject to an appeal that is pending before the North Carolina Supreme Court.

The northeastern counties of Camden, Currituck, Dare and Tyrrell were assigned to North Carolina Natural Gas Corporation because they are contiguous to NCNG's existing territory. The previously unfranchised parts of Montgomery and Moore Counties were assigned to NCNG because NCNG already had a franchise for parts of those counties.

I should mention one other matter noted on the map. Warren County is now in the franchise territory of Public Service, but there is no natural gas service in the county at present. Frontier has recently filed an application for a franchise for Warren County. The Commission has scheduled a hearing on Frontier's application and the Commission will be deciding that matter soon.

The Commission is glad to see all of the State map finally "filled in" and I am sure that you are as well. A few of the assignments may change as the pending matters that I have mentioned are decided, but the assignment of franchises for all of the State is an important milepost in getting natural gas service extended throughout the State, and I am glad to be able to report this development to you.

Natural Gas Expansion Reports

Turning to my next subject, G.S. 62-36A requires the natural gas local distribution companies (or LDCs) to file biennial reports with the Commission on their plans for providing natural gas service in unserved areas of North Carolina, and it requires the Commission to report to this Committee on the status of natural gas service within the State and on the reports filed by the LDCs. The LDCs filed their latest reports in October 1995, and the Commission filed its report with the Committee on May 1, 1996. I am here to give you an oral summary of these reports today.

NCNG, in its report, identified three expansion projects planned for the 1996-1998 time frame. The first involves the construction of a new 71-mile pipeline that will provide initial natural gas service to Duplin and Onslow Counties. This project was approved for expansion funding and consists of the construction of a new transmission pipeline running from Mount Olive to Warsaw, and then turning southeast through Duplin County and on to Jacksonville and Camp Lejeune. Limited distribution systems are also included in Faison, Kenansville, Jacksonville, and at Camp Lejeune. The towns of Faison and Kenansville and the City of Jacksonville, as well as Duplin and Onslow Counties, have committed financial assistance in the form of five annual payments to NCNG's expansion fund in amounts equaling 100% of the ad valorem tax revenues collected on the facilities constructed as part of this project. The total cost of this extension, which will provide initial gas service to Duplin and Onslow Counties, is estimated to be $18.8 million. NCNG's shareholder investment in this project is estimated to be $6.4 million, with the expansion fund providing $12.4 million, the negative NPV of the project. This project was approved for use of expansion funds in August of 1995; however, there was a delay in determining whether federal officials would require an environmental assessment before construction across federal land, and therefore actual construction has not yet commenced. An environmental assessment has been required, and the Commission has required NCNG to report in March on the status of this project.

The second project identified is an extension of natural gas service to the Whiteville/Columbus County Industrial Park. This extension consists of the construction of 17 miles of 6" transmission pipeline from an interconnection with the Company's existing 12" line near Bladenboro in Bladen County to the Columbus County Industrial Park west of the town of Whiteville. This project will increase the availability of natural gas in Columbus County and will be the first natural gas service to the Whiteville area. The total cost of the project is estimated to be $1.8 million and NCNG will be responsible for approximately $500,000 of this total pursuant to its agreement with Columbus County. This project was included in NCNG's previous biennial report, but construction, which was originally scheduled for 1994, was delayed. NCNG indicates that this project is virtually complete. No expansion funds were used in this project.

The third project consists of approximately 5 miles of 4" transmission line which will be installed in Bladen County to serve a new industrial plant, Accent Dyeing & Finishing, Inc., and will also make natural gas service available within Elizabethtown. This will be the first natural gas service to the Elizabethtown area. Bladen County has committed to use up to $544,000 of available Community Development Block Grant Funds to construct this pipeline. NCNG has agreed to fund the remainder of the project cost which is estimated not to exceed approximately $200,000. Construction of this project is anticipated to be completed in March of this year.

NCNG also identified a potential project which is under consideration at this time. This project would provide initial gas service to Bertie and Martin Counties and would be constructed in two phases. Phase I would include 15.5 miles of 12" steel transmission pipeline from Transco's delivery point at Ahoskie to Lewiston in Bertie County. It would also include a 6" steel lateral running approximately 2.7 miles to serve industrial customers. The estimated construction cost for Phase I of this project is approximately $6.0 million. The NPV for this portion of the project is a negative $3,931,400. Phase II of this extension would run from Lewiston to Robersonville in Martin County. It would include approximately 22.4 miles of 12" steel transmission line and a 500 ft. 6" steel lateral to an industrial customer. In addition, this project would include approximately 1.8 miles of 6" plastic distribution lines inside the town of Robersonville. The total cost for Phase II is estimated to be about $8.5 million. The NPV for this phase is a negative $3,786,500. NCNG estimates that the total construction cost for this new pipeline to serve portions of Bertie and Martin Counties would be approximately $14.5 million. The NPV for the project as a whole is negative $7,717,900. Neither the feasibility nor the timing of this project has been determined at this point. NCNG states that it will be analyzing this project in more depth in the months ahead. According to NCNG, a decision will then be made as to whether to request approval to use expansion funds for partial funding for this project. If they are approved, construction would most likely occur toward the end of the 1996-1998 time period covered by NCNG's report.

In addition to the four major projects currently planned or under consideration as noted above, NCNG has identified 19 projects, each of which will require expenditures in excess of $100,000, during the next three-year period. The 19 projects have a total budgeted cost of approximately $3.4 million.

With respect to N.C. Gas, the only incorporated town in the Company's service territory that is not served by natural gas is Stoneville in Rockingham County. N.C. Gas has evaluated the cost and economic feasibility of serving Stoneville. The Stoneville project consists of 4.3 miles of high pressure pipeline and a distribution system to serve the community of Stoneville and is estimated to cost approximately $1.8 million. N.C. Gas has performed an NPV analysis for the Stoneville project and determined that it is not economically feasible to extend service to that community. The NPV analysis included with the Company's report shows that approximately $500,000 is needed to make this project feasible. N.C. Gas stated in its report that it intends to ask the Commission for authority to utilize expansion funds for this project. The town of Stoneville has granted the Company a franchise for a gas distribution system within the town limits. If the Commission approves the use of expansion funds, N.C. Gas indicates that it expects to extend service to Stoneville within the next three years.

Since its last biennial report, N.C. Gas has undertaken two projects. Service has been extended to Walnut Cove and Shady Grove using the Company's own funds. The Company has invested over $2 million and added over 1,000 services and 33 miles of transmission and distribution mains since the end of the 1993 fiscal year. The Walnut Cove and Shady Grove projects represent approximately 46% of this investment.

Piedmont's 1996 biennial report identified several projects for which management has approved preliminary plans and budgets. The primary expansion project identified was the extension of service into the four-county area of Surry, Watauga, Wilkes and Yadkin counties. However, as you know, the franchise for these four counties was subsequently granted to Frontier, and Piedmont has appealed this matter to the Supreme Court. Other expansion projects identified by Piedmont include expansions into Catawba and Caldwell Counties. The first project would provide service to the industrial section east of Claremont in Catawba County. This expansion would provide service to 5 commercial and 2 industrial customers at a cost of approximately $434,397. The second project would extend service along Highway 18 from Lenoir to the town of Gamewell in Caldwell County. The cost of this project is estimated to be $184,256 and would provide service to a mixture of residential and commercial customers. The NPV of this project is $6,747.

Piedmont's biennial report also identified eight potential expansion projects that it said may be carried out depending on the resolution of each project's economic feasibility issues. One of these was expansion into Stokes County, where Piedmont did not have a franchise at the time the report was filed. Since then, as I stated earlier, Piedmont has been granted a franchise for most of Stokes County and, as a part of that franchise proceeding, Piedmont stated that it would not use expansion funds in connection with its Stokes County project. Other potential projects identified in Piedmont's report involve expansion within Alexander, Davidson, Guilford, Lincoln, Forsyth and Randolph counties. Excluding the Stokes County project, these projects have a total estimated cost of $9.7 million and a negative NPV of $3.8 million.

In Piedmont's 1994 biennial report, it identified 62 new projects which required capital expenditures of $100,000 or more, 38 of which Piedmont reported as still in-process. As of the date of its 1996 biennial report, 18 of these 38 projects were still in-process. Since the 1994 filing, Piedmont has initiated 98 additional projects, each requiring capital expenditures of $100,000 or more. Thirty-four of these projects have been completed and 64 are still in-process. The cost to complete the 64 projects is approximately $8 million.

Since its last biennial report, PSNC has initiated an expansion of natural gas service into previously unserved McDowell County. This project includes approximately 20.5 miles of 12" transmission pipeline beginning near Black Mountain in Buncombe County and continuing to Old Fort and Marion in McDowell County. The proposed expansion also includes a limited amount of distribution mains in the town of Old Fort and City of Marion. The town of Old Fort, City of Marion and McDowell County have submitted resolutions to provide PSNC five annual payments equal to 100% of the property taxes collected on natural gas facilities constructed as part of the proposed McDowell County project. These local government assistance payments will act as a direct contribution to PSNC's expansion fund. The total cost of this extension, which provided initial gas service to McDowell County, was approximately $14 million. PSNC has received $7.8 million from its expansion fund and expects to receive $412,500 in contributions in the form of local government assistance payments. This project was completed in December 1996.

PSNC also has budgeted for 26 new projects, each requiring expenditures of $100,000 or more. Thirteen are located in Wake County, 5 are in Cabarrus County, 3 each are in Iredell and Buncombe Counties and 1 each will be located in Alamance and Haywood Counties. Over $8.9 million is to be spent, with 38% of that amount going for mains and the remaining 62% invested in services and other costs. Based upon the assumptions utilized by PSNC in performing its feasibility analyses, these projects reflect a combined NPV of $3.8 million.

PSNC's 1996 biennial report lists four major projects in addition to the McDowell County project that are not economically feasible and therefore will require the use of expansion funds. These projects are (1) the extension of gas in Haywood County to the town of Waynesville, (2) eastward in Franklin County to Louisburg and eastward in Wake County to Wendell and Zebulon, (3) Alexander County including Taylorsville and (4) Warren County including Warrenton. Since filing its report, on December 30, 1996, the Company filed an application for approval to use its expansion fund for the first of these projects, the extension of service to western Haywood County, and to withdraw up to $5 million in expansion funds for this project. In this application, Public Service advised the Commission that it currently plans to file an application to serve Alexander County, including Taylorsville and Hiddenite, in 1998 and that it is considering a variety of options to provide service to the seven new counties recently assigned to it.

It was the Commission's overall conclusion that each LDC's plan for expansion of natural gas service within its franchise territory in North Carolina is reasonable.

Kolt. Craker 1/14/97

APPENDIX E

THE STATUS OF NATURAL GAS SERVICE IN NORTH CAROLINA

FINANCIAL STRENGTH OF NORTH CAROLINA LOCAL DISTRIBUTION COMPANIES

North Carolina Natural Gas Corporation (NCNG) is a publicly-held, natural gas local distribution company listed on the New York Stock Exchange (ticker symbol is NCG). At December 31, 1995, NCNG employed 532 persons and provided natural gas service to over 140,600 customers in south central and eastern North Carolina through a system comprised of almost 3,600 miles of gas mains, five compressor stations, and a Liquified Natural Gas (LNG) storage facility. NCNG, which is the only North Carolina LDC physically connected to two interstate pipelines, has an interconnection with both Transco's and Columbia's interstate pipeline systems.

NCNG's franchise territory, which consists of 47 eastern and south central North Carolina counties, which covers over half the area of the State. The 47 counties include the four counties recently assigned to NCNG. The population of the franchise area is 2.4 million and the population density is 100 persons per square mile, considerably below the 147 persons per square mile average for the State. NCNG's customer mix consists of 87% residential, 12% commercial, and less than 1% industrial customers. Industrial customers, although a very small portion of total customers, use approximately 70% of NCNG's gas deliveries. At September 30, 1995, NCNG's total capitalization was over $150 million and consisted of approximately 60% common equity and 40% debt. Its net income has ranged between $11 million and $12 million for each of the last three fiscal years.

NCNG provides service to customers in 29 of the 47 counties in its franchise area. Within these 29 counties, 63 cities and towns, as well as four municipal gas systems, are served.

NCNG serves approximately 17% of the households in the counties in which service is currently provided, as compared to approximately 12% in 1989.

The eighteen totally unserved counties in NCNG's franchised area are: Bertie, Camden, Carteret, Chowan, Currituck, Dare, Duplin, Gates, Hyde, Jones, Martin, Onslow, Pamlico, Pasquotank, Pender, Perquimans, Tyrell, and Washington. Montgomery and Moore Counties are only partially served.

Public Service Company of North Carolina (PSNC) is a publicly-held, natural gas local distribution company listed on the New York Stock Exchange (ticker symbol is PGS). PSNC employs 1,130 persons and provides natural gas service to approximately 294,000 customers.

PSNC was founded in 1937, and as the result of several mergers and acquisitions, its territory is composed of the following three noncontiguous areas: (1) the eastern section, which includes the Research Triangle, seven surrounding counties, and a small portion of Alamance County; (2) the piedmont section, which includes Iredell, Cabarrus, and Alexander Counties, a portion of Rowan County and the northeastern tip of Mecklenburg County; and (3) the western section, which now includes all counties between Gaston County and Cherokee County. Prior to the assignment to it of seven additional western counties, the population of its service territory was 2.1 million and its population density was 203 persons per square mile. This compared to 147 persons per square mile for the rest of the State. The overall density will be lower now.

At December 31, 1995, PSNC's total capitalization was over $350 million, and consisted of approximately 50% common equity and 50% debt. Its net income was between $21 and $22 million for each of the last two years.

PSNC provides service in 23 out of the 33 counties comprising its franchise area. Within its service area, it serves 87 communities. PSNC serves approximately 33% of the households in the counties where natural gas service is generally available, compared to a rate of 26% in 1988.

Prior to being assigned seven new counties in August, 1996, the three totally unserved counties in PSNC's franchised area were Alexander, McDowell, and Warren. In addition, gas service is being provided to only a very small portion of two other counties, Franklin and Haywood. In December, 1996 PSNC's expansion project to McDowell County was completed. PSNC also has developed preliminary plans to extend service into the center of Haywood County and introduce service to its portion of Alexander County. PSNC currently has no plans to serve the seven new western counties recently assigned to it. Frontier has applied to serve Warren County, and PSNC has indicated that it will not oppose its application.

Piedmont Natural Gas Company is a publicly-traded natural gas local distribution company that is listed on the New York Stock Exchange (ticker symbol is PNY). Piedmont employs approximately 2,000 persons and provides natural gas service to over 510,000 residential, commercial, and industrial customers in the piedmont region of North and South Carolina and in the Nashville, Tennessee area. In North Carolina, Piedmont provides natural gas service to approximately 310,000 customers through a system comprised of approximately 400 miles of transmission lines, one liquified natural gas (LNG) plant, and 6,743 miles of distribution line. Piedmont has access to gas supplies through its physical connections with the Transco interstate pipeline.

Before Piedmont was assigned additional counties, its franchise territory consisted of all or parts of 14 counties in the piedmont region of the state, and covered 5,649 square miles. The population of the area is approximately 2 million and its average population density is 356 persons per square mile, which is considerably higher than the 147 persons per square mile average for the State. The Commission has recently assigned Avery, Yancy and Mitchell Counties and the majority of Stokes County to Piedmont. This will lower the average population density of its territory considerably.

Piedmont's customer mix consists of 86% residential, 14% commercial, and less than 1% industrial customers. Gas deliveries to North Carolina customers for the year ended October 31, 1995, consisted of 28% residential, 17% commercial, and 55% industrial. At October 31, 1995, Piedmont's total capitalization, including short-term debt and current maturities, was over $736 million which consisted of approximately 48% common equity and 52% debt. Its net income has ranged between $36 million and $40 million, over the last three fiscal years.

North Carolina's LDCs have had a high demand for their services, and this demand is requiring them to make considerable investment in capacity, transmission and distribution plant.

During the 1991-1995 period, NCNG invested $98.4 million in new plant, an increase of over 40 percent. This new construction facilitated the addition of 28,300 new customers. The customer growth rate during this period averaged 5.4% per year.

During the 1991-1995 period, Public Service invested $214.2 million in new plant which facilitated the addition of 47,221 new customers. The customer growth during this period averaged 4.7% per year.

During the same period, Piedmont invested $208 million in new plant. This facilitated the addition of 62,518 new customers. The customer growth rate averaged 5.8% per year.

Attached to this speech are three pie charts which show where the construction budgets of the three LDCs were allocated. Generally, most of their budgets are spent in expanding service within cities and towns where construction costs are lower and potential returns are greater.

The LDCs' finance expansion projects through the use of traditional financing and/or expansion funds. Traditional financing includes the company's internal generation of funds and the acquisition of funds external to the company in the capital markets. Internally generated funds are essentially the LDCs' retained earnings that are not paid to shareholders as dividends. LDCs raise funds externally through the sale of debt securities, preferred stock and common stock. By utilizing a combination of traditional financing and expansion funds, LDCs can extend gas service to unserved counties that would otherwise not be economically feasible to serve. The amount of expansion funds which can be used for a project is the amount required to make it profitable (zero net present value) over the long run. The LDC must raise the remaining capital for expansion projects from the traditional sources that it utilizes for its profitable projects. Expansion projects must compete with profitable projects for the LDCs' limited resources.

Because gas expansion using traditional financing sources increases an LDC's rate base (the amount of investment on which it is allowed to earn a profit), an LDC has the incentive to extend service to new areas whenever the investment is profitable. The amount of new investment is limited, however, by the amount of capital that an LDC can raise internally and externally. The profitability of the new investment and the profitability of the LDC as a whole could be adversely affected if the LDC attempts to finance new investment out of proportion to its size or financing capability. Two measures commonly used to evaluate the financing capability of an LDC to finance expansion are the following:

(1) the amount of internally generated funds that are not paid to shareholders as dividends. An LDC with a low internal generation is experiencing a large amount of new investment relative to the profits from its ongoing operations.

(2) capital expenditures as a percent of total capitalization - the amount of new investment divided by the total debt and equity capital of an LDC. An LDC with a high ratio is considered to have a relatively large construction program.

An overly aggressive gas expansion program could cause an LDC to be viewed as having greater risk by the financial community. The financial markets may place limits on the amount of external financing that an LDC can raise by increasing its cost to borrow funds or decreasing the market price of its stock. An LDC faced with more profitable investment options than available reasonably-priced capital is forced to allocate its resources among competing expansion projects in the most profitable manner possible. If an LDC attempts too much expansion, it runs the risk of raising its cost of capital for all projects which could have a negative impact on profitable and unprofitable expansion efforts. This could also put upward pressure on rates.

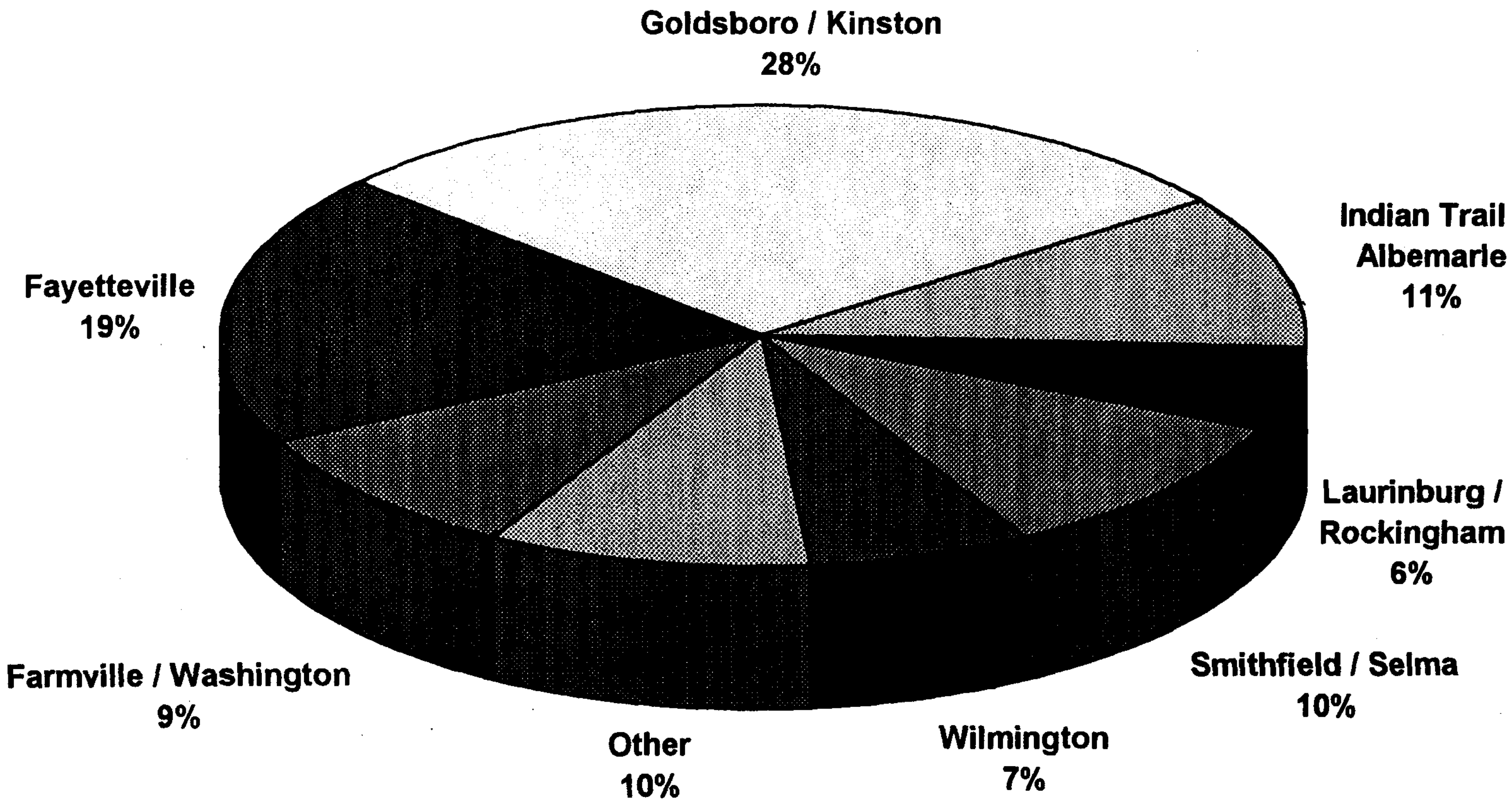
Our staff compared the performance of our LDCs with respect to these two key reasons to two comparison groups: (1) a group of 28 LDCs covered by the Edward D. Jones Brokerage firm and (2) a select group of 14 LDCs which experienced above average annual growth.

Attached is a comparison of key ratios chart shows that during the five year period 1991-1995, the three LDCs experienced a higher customer growth rate than the LDC comparison group (fast growing) and the 28 LDCs covered by Edward D. Jones. The three LDCs were able to internally generate funds at a level comparable to the comparison group. The comparison shows that all three had lower levels of expenditures per additional customers than the comparison groups. Finally, the comparisons show that all three had greater expenditures relative to their size than the comparison groups. These comparisons lead us to conclude that although our LDC's have relatively large construction programs due to a high rate of growth, they have been able to maintain internal generation of funds at levels comparable to other LDCs.

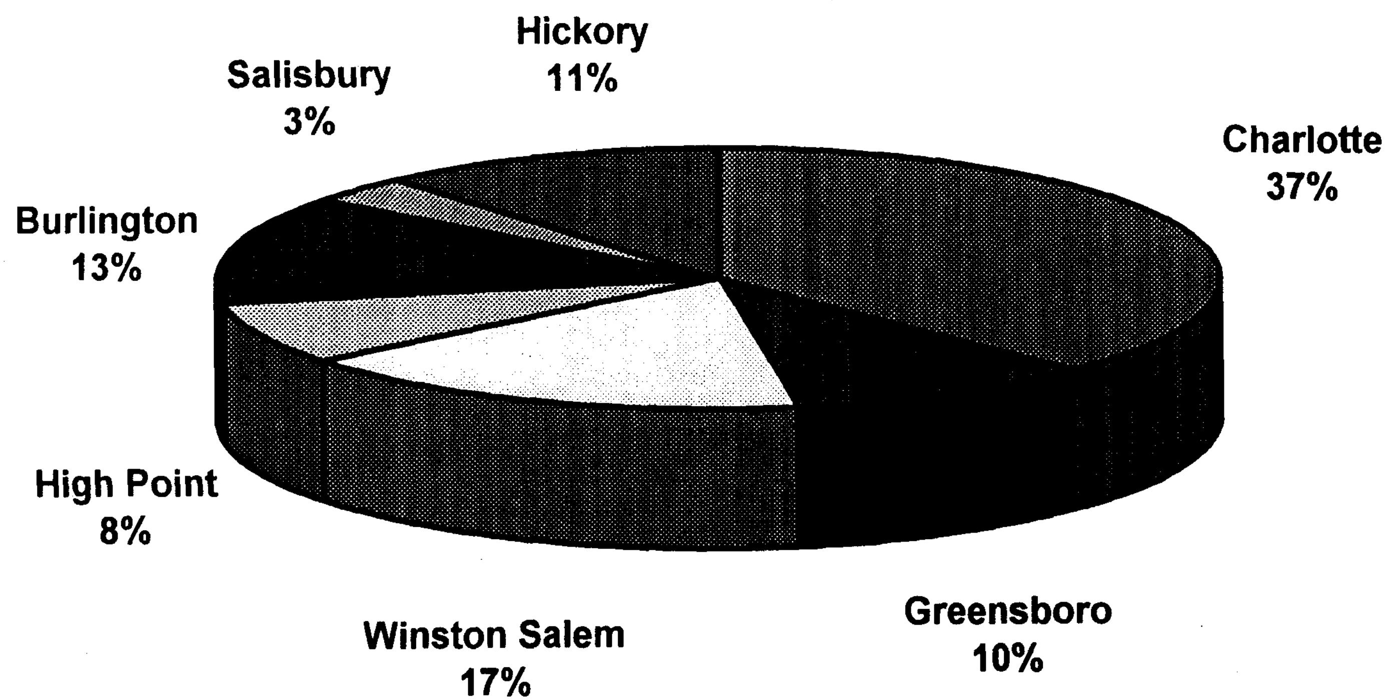
Some further indication of the financial strength of the three companies is reflected in their Standard &Poor's debt ratings. Piedmont's debt is rated A and Public is rated A-. There is no S&P rating available for NCNG because their debt was placed privately. Value line rates all three as B+++, which is a superior relative financial strength. Thus we conclude that our LDCs have to date managed their high growth rates very well, and that they are financially healthy.

Finally, I want to point out that the LDCs, the Commission, and the legislature need to balance the LDCs growth and expansion in a way to keep rates affordable. Historically, natural gas has been relatively inexpensive compared to other energy sources. However, colder than normal weather in November has caused this winter's cost of gas to increase dramatically. This has caused natural gas rates this winter to be 20-25% higher than last year's rates. Hopefully, the cost of producer gas will return to lower levels, but this current spike in rates is a warning that we cannot take low gas rates for granted.

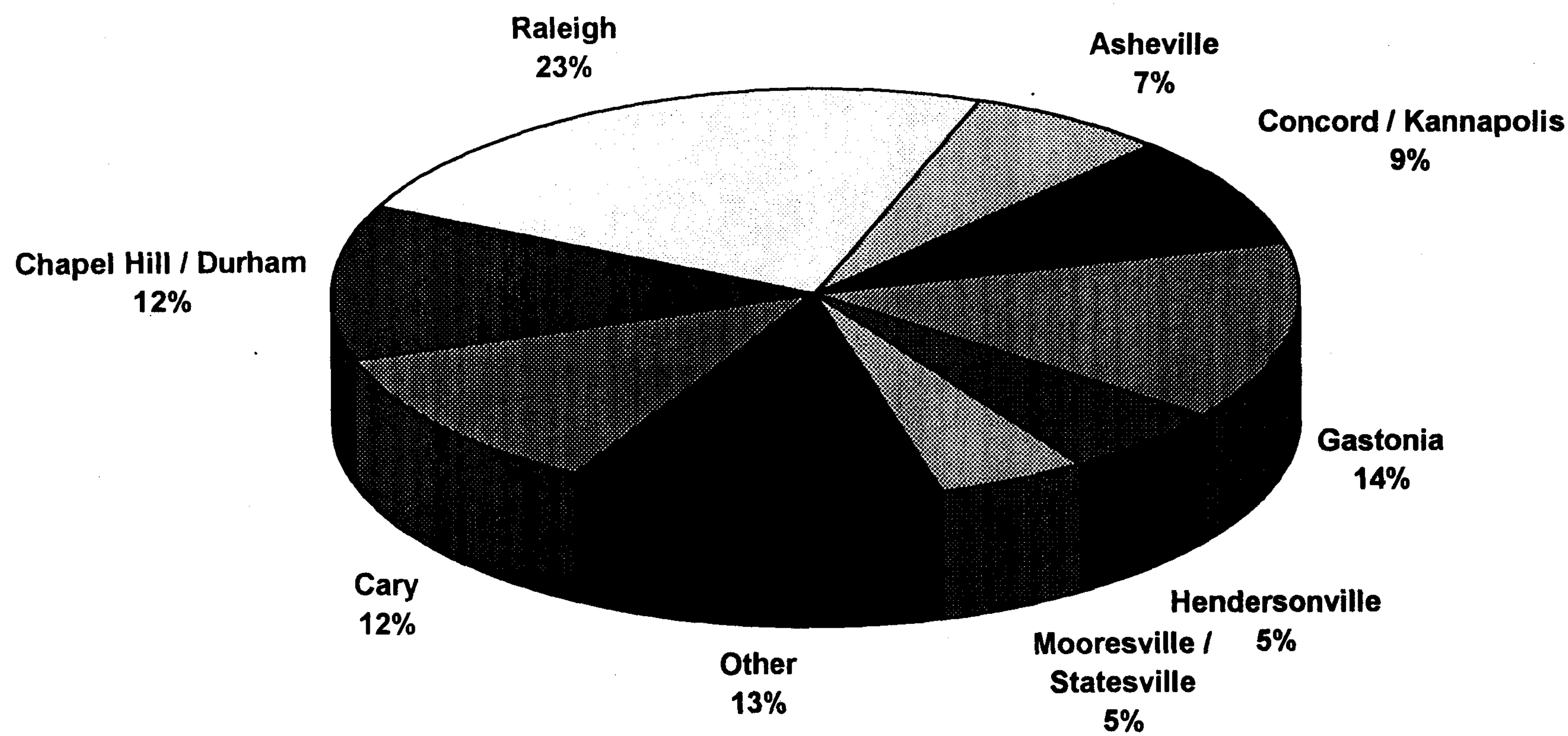
North Carolina Natural Gas Company
Regional Construction Expenditures
For Fiscal Years Ending September 30, 1994 and 1995



Piedmont Natural Gas Company, Inc.
Regional Construction Expenditures
For Fiscal Years Ending October 31, 1994 and 1995



Public Service Company of North Carolina, Inc. Regional Construction Expenditures For Fiscal Years Ending September 30, 1994 and 1995



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North Carolina LDC's

January 1997

	NCNG	NUI Corp.	Piedmont	Public Service
S & P Debt Rating	Not Rated [1]	BBB	A	A-
Value Line:				
Financial Strength [2]	B++	B+	B++	B++
Safety [3]	2	3	2	3

Notes:

[1] All debt has been privately placed.

[2] Financial Strength range from highest to lowest: A++, A+, A, **B++, B+**, B, C++, C++, C

[3] Safety range from highest to lowest: 1, **2, 3**, 4, 5

1/13/97

Comparison of Key Ratios
Five-Year Averages
As of the 1995 Fiscal Year

Item	Major North Carolina LDCs			Comparison Groups	
	NCNG	PSNC	Piedmont	14 High Growth LDCs	28 Edward D. Jones LDCs
Customer Growth Rate	5.40%	4.70%	5.80% [1]	4.00%	2.40%
Internal Generation of Funds	60%	55%	52%	55%	59%
Construction Expenditures per Added Customer Ratio	$3,434	$3,747	$3,457	$4,661	$6,508 [2]
Construction Expenditures to Total Capitalization Ratio	16%	15%	14%	13%	12%

1 Piedmont's customer growth rates are 6.6% for North Carolina and 5.8% for its total system, which includes territories in North Carolina, South Carolina and Tennessee.

2 Due to the skewed distribution of the E.D. Jones LDCs, a median value is presented for the Construction Expenditures per Added Customer ratio.

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VALUE LINE MEASURES

FINANCIAL STRENGTH

A relative measure of financial strength of the companies reviewed by Value Line. The relative ratings range from A++ (strongest) down to C (weakest), in nine steps.

A++	Supreme relative financial strength
A+	Excellent financial position relative to other companies
A	High-grade relative financial strength
B++	Superior financial health on a relative basis
B+	Very good relative financial structure
B	Good overall relative financial position
C++	Satisfactory finances relative to other companies
C+	Below-average relative financial position
C	Poorest financial strength relative to other major companies

SAFETY

A measurement of potential risk associated with individual common stocks. The Safety Rank is computed by averaging two other Value Line indexes the Price Stability Index and the Financial strength Rating. (The Price Stability Index is a measure of the stability of a stock's price. It includes sensitivity to the market (see BETA) as well as the stock's inherent volatility. Price Stability ratings range from 100 (highest) to 5 (lowest)). Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit their purchases to equities ranked 1 (Highest) and 2 (Above Average) for Safety.

TABLE 4

COMPARISON OF NORTH CAROLINA GAS UTILITIES' AVERAGE UNIT RATES AND AVERAGE COST OF PURCHASED GAS

YEAR ENDING DEC. 31	DESCRIPTION	NORTH CAROLINA NATURAL GAS ($/DT)	PIEDMONT NATURAL GAS ($/DT)	PUBLIC SERVICE CO. ($/DT)	N. C. GAS SERVICE ($/DT)
1989	Cost of Gas	$2.8743	$2.5611	$2.8358	$3.2400
	Residential Rates	6.1460	6.2465	6.7007	6.0034
	Commercial Rates	5.1550	5.2786	4.8673	5.1809
	Industrial Rates	3.3436	4.0187	3.5317	2.9448
1990	Cost of Gas	3.0380	2.9360	2.6946	3.3200
	Residential Rates	5.8406	5.6981	6.3935	5.6554
	Commercial Rates	4.7051	4.5434	4.4461	4.7134
	Industrial Rates	3.4800	3.2990	3.3280	3.9350
1991	Cost of Gas	2.7140	2.7903	2.4053	2.9800
	Residential Rates	5.5604	5.9261	6.4140	5.9116
	Commercial Rates	4.4516	4.6688	4.2271	4.9845
	Industrial Rates	3.0941	3.2771	3.1985	3.1510
1992	Cost of Gas	2.7077	2.7107	2.6969	3.2500
	Residential Rates	5.6075	6.0750	6.8036	5.9962
	Commercial Rates	4.3105	4.8369	4.6541	4.8659
	Industrial Rates	3.1405	3.3748	3.3712	3.2589
1993	Cost of Gas	3.0254	2.9569	3.0636	2.8666
	Residential Rates	6.5385	6.5528	7.1605	6.0408
	Commercial Rates	5.4792	5.4680	5.2030	4.9679
	Industrial Rates	3.7015	3.3296	3.7970	3.2047
1994	Cost of Gas	2.8750	3.2286	3.1047	3.2271
	Residential Rates	6.5508	6.8102	7.5771	6.5937
	Commercial Rates	5.0736	5.6941	5.5804	5.4358
	Industrial Rates	3.4982	3.7796	3.9626	3.3989
1995	Cost of Gas	2.4892	3.0559	3.0325	3.0400
	Residential Rates	5.9594	6.4551	7.5858	6.4542
	Commercial Rates	4.4097	5.3528	5.2821	5.2169
	Industrial Rates	3.1847	3.4370	4.1559	3.8917
1996	Cost of Gas	3.4284	3.6195	3.4419	
	Residential Rates	6.6992	6.6791	7.2505	
	Commercial Rates	5.3155	5.7718	5.6341	
	Industrial Rates	3.7330	4.1521	3.8605	
1/1/97	Cost of Gas				
	Fixed	0.6749	0.8601	0.8943	
	Commodity	3.7000	3.7200	3.3000	
	Combined	4.3749	4.5801	4.1943	
	Residential Rates	8.2518	8.9527	9.2918	
	Commercial Rates	6.4635	7.4934	6.8232	
	Industrial Rates	4.3595	5.2642	5.5188	